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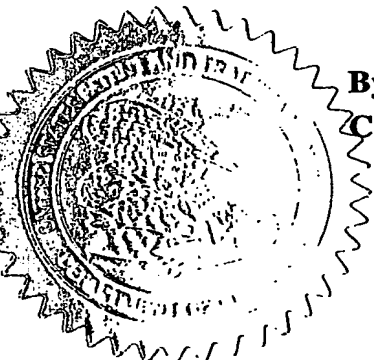
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APPLICATION NUMBER: 60/510,596

FILING DATE: October 10, 2003

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Docket Number		103.0010 PSP		Type a plus sign (+) inside this box ->	+
INVENTOR(s)/APPLICANT(s)					
LAST NAME	FIRST NAME	MIDDLE INITIAL	RESIDENCE (CITY AND EITHER STATE OR FOREIGN COUNTRY)		
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TITLE OF THE INVENTION (280 characters max)					
HORIZONTAL WATER INJECTION WELL TEMPERATURE ANALYSIS AND SIMULATION					
CORRESPONDENCE ADDRESS					
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STATE	Texas	ZIP CODE	77583-1590	COUNTRY	U.S.A.
ENCLOSED APPLICATION PARTS (check all that apply)					
<input checked="" type="checkbox"/>	Specification	Number of Pages	58	<input type="checkbox"/>	Small Entity Statement
<input checked="" type="checkbox"/>	Drawing(s)	Number of Sheets	0	<input checked="" type="checkbox"/>	Other (specify) Post Card
METHOD OF PAYMENT (check one)					
<input type="checkbox"/>	A check or money order is enclosed to cover the Provisional filing fees			PROVISIONAL FILING FEE AMOUNT (\$)	\$160.00
<input checked="" type="checkbox"/>	The Commissioner is hereby authorized to charge filing fees and credit Deposit Account Number: 50-2475				

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101003

The invention was made by an agency of the United States Government or under a contract with an agency of the United States Government.

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Respectfully submitted,

SIGNATURE

Date

10/10/2003

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41,660

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IN THE UNITED STATES PATENT & TRADEMARK OFFICE

Applicant: Bui et al.

Attorney Docket No: 103.0010 PSP

Serial No:

Art Unit:

Filed:

Examiner:

For: **HORIZONTAL WATER INJECTION WELL TEMPERATURE ANALYSIS
AND SIMULATION**

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IN THE UNITED STATES PATENT & TRADEMARK OFFICE

United States Provisional Patent Application

For

**Horizontal Water Injection Well
Temperature Analysis and Simulation**

By

Thang D. Bui, Yannong Dong and Younes Jalali

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Summary

This research studied the temperature behavior in the wellbore of the horizontal water injector, using the reservoir simulation with the multi-segment well model. It examined the applicability of the analytical interpretation methods to estimate the flow profile from the temperature data. The result of this study indicates that the temperature data during early injection time and during shut-in period can be used for estimation of the injection profile along the wellbore.

Temperature during early injection time (within few hours immediate after beginning of the injection) can be used for estimation of the injection profile with simple analytical method, provided enough temperature contrast between injected fluid and the fluid inside the wellbore. At a later time of injection, when the temperature profile stabilizes, the temperature data gives qualitative information of the injection profile.

Analytical method for interpreting the temperature profile during shut-in period gives detail flow profile along the wellbore. The shut-in analysis for the well with short injection history gives better estimation of the injection profile compared to the one with long injection history.

With the enormous data that permanently installed Distributed Temperature Sensing (DTS) can produce from a horizontal injection well, identification of the method of analysis, the applicability of the analysis method, and the type of data for analysis are very important. This study gives some insight into and the answer to these questions.

Introduction

The temperature logging has been used long time in the past for profiling the injection rate in the vertical well. The analysis techniques for temperature data were based on the temperature profile in the wellbore during shut-in period following the injection. During the injection, the temperature in the wellbore at the injection interval depends mostly on the convection heat rate (the heat carried by fluid). The thickness of the injection interval is short, thus the temperature is essentially constant and equal the temperature of the fluid at the top of the injection interval (Fig. 1).

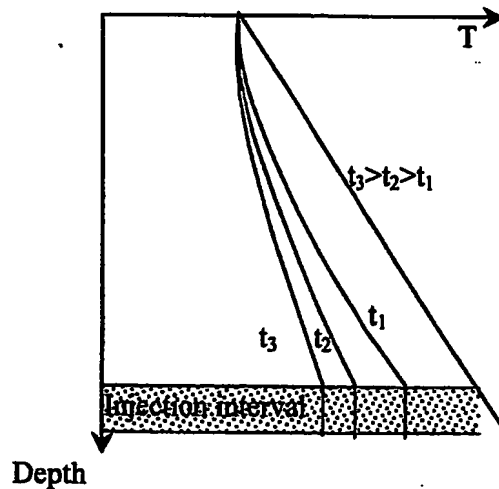


Fig. 1 – Temperature in the vertical well during injection

After shut-in, heat is transferred from undisturbed region of the reservoir to the fluid in the wellbore mostly by conduction (Fig. 2). This process leads to the increasing of the

temperature in the wellbore and is called the temperature recovery from injection. The rate and the magnitude of the temperature recovery depend on the total heat exchange between formation and fluid at each location along the wellbore, which is determined by the injection rate into reservoir at that interval. Temperature at the interval, which accepted more injected water will rise slower than other intervals. Analyzing the rate of the temperature recovery in the wellbore allows inferring the injection profile of the well.¹⁻⁵

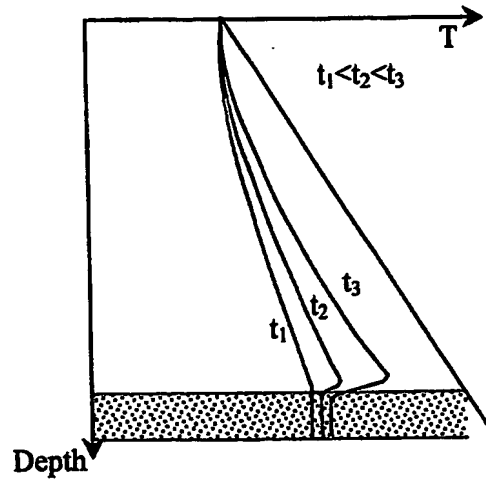


Fig. 2 – Temperature profile in the vertical well during shut-in

Existing methods of analysis of injection profile target the vertical well, where the injection interval is usually small and the effect of finite wellbore volume can be neglected. Further more, the displacement process of the reservoir fluid can be depicted by radial flow model with reasonable accuracy. For horizontal well, the displacement process occurred along long wellbore. The flow regime starts with radial (if $k_z = k_x = k_y$) or elliptical (if k_z is much smaller than k_x, k_y) and changes to linear flow in the direction normal to wellbore. At the later time of injection, the effect of heat conduction from the

cap and base formation can mask the heat conduction in the horizontal direction. The finite volume of the wellbore in the horizontal section also contributed to possible deviation from existing method of injection profile analysis. All these factors combined can make the behavior and the interpretation of temperature in horizontal injector far different from that in the vertical well.

The growing number of the horizontal wells and the development of the new technology to accurately measure the temperature in the well without well intervention (DTS) revitalize the interest in the temperature logging. Because of the lack of the theory and experience in interpreting the temperature in horizontal well, there is a need for a solid understanding of the temperature behavior in the horizontal well and to establish the procedure for using and interpreting the temperature data from horizontal injection well. This study addressed these problems.

The objective of this study is to:

- Gain insight of the temperature behavior in the horizontal water injector, and identify the difference in temperature behavior between vertical and horizontal well.
- Investigate the use of the DTS data for the injection profiling in horizontal water injector, specifically: the method for analysis temperature data and the type of temperature data for analysis.

Approach

I choose to approach this problem by using the thermal reservoir simulation with the option of calculating the temperature at any point along the length of the well.^{6,7} The reservoir simulation, which conserves the mass and energy balances of the well-reservoir system, allows investigating the effect of different factors on the temperature profile of the well. These factors such as the anisotropy and 3D dimension of the injection process otherwise could not be captured by the analytical solution. Following stages have been performed to achieve the goal of the study:

- building the simulation model to study the temperature behavior in the well and the factors that affect the temperature profile.
- reviewing the existing interpretation techniques and assessing the applicability of these methods for horizontal well using simulated and real temperature profiles.
- using the simulation model to evaluate the applicability of the interpretation technique in analyzing the temperature data from the actual well.

Key Results

The key results from this study are:

- The temperature data during early injection can be used for estimation of the injection profile. This required high frequency temperature along the wellbore within few hours of injection.
- At a later time of injection, when the temperature stabilized, the temperature profile provides qualitative information of the injection profile in the well.
- The shut-in data gives more detail information of the injection profile than the data during injection. The new analytical method, which assumes two distinctive temperature regions in the reservoir at the shut-in gives good estimation of flow profile compared to the simulated flow result. The shut-in analysis for the well with short injection history gives better estimation of the injection profile compared to the one with long injection history.
- Simulation is a good tool for justifying the estimated flow profile and for incorporating other variables (such as pressure distribution, formation permeability distribution) into the analysis. In using simulation to investigate the temperature behavior in well, it is important to choose the right grid scheme and grid size around the wellbore.

Simulation Study

This section briefly described the simulation model and the temperature behavior of the well during injection and shut-in. The model simulates the single horizontal water injector in a bounded reservoir. Special attention has been paid to the selection of the right block size around the wellbore. The specific features of the temperature profile in homogeneous and heterogeneous reservoir are discussed.

Simulation Model

Fluid Model. The simulator used in this study is compositional Eclipse-300. The fluid in the reservoir is modeled by two components, one is C1 (40%), the other is C7+ (60%). The mixture of these two components under the reservoir condition used in this study results into an undersaturated oil with GOR of 300 scf/STB and bubble point pressure of 2500 psi.

Reservoir model. The reservoir is of 110 ft thick with the aerial extend of 7000 ft in X direction, 4100 ft in Y direction. It is filled with oil and irreducible water saturation of 0.2. Porosity of the reservoir is 0.2 and kept unchanged throughout the course of the study. The thermal capacity of the rock is constant. The thermal conductivity and the permeability of the reservoir are subject to change during the course of the study. Table 1 shows the basic parameters used in this simulation study.

TABLE 1 – BASIC RESERVOIR PARAMETERS

Reservoir thickness, ft	110
Permeability, md	3
Porosity	0.2
Initial bubble point pressure, psi	2500
Irreducible water saturation	0.2
Geothermal gradient, °F/ft	0.02
Temperature at top of the formation, °F	210
Rock heat capacity, Btu/ft ³ -°F	35
Rock thermal conductivity, Btu/ft-D-°F	24

Well model. The well is horizontally completed at the center of the reservoir in the X direction and is modeled as a number of segments with the ID of 0.45 ft. The pressure

drop in each segment is calculated using homogeneous flow model. The heat transfer coefficient between wellbore segment and reservoir is calculated based on the formation thermal conductivity between the wellbore and the well block. In doing so, we assumed that the fluid inside the well segment have the same temperature as calculated at the sandface. The well parameters and its thermal heat resistance coefficient are given in Table 2.

TABLE 2 – WELL PARAMETERS

Well ID, ft	0.45
Wellbore roughness, ft	0.001
Well length (open hole), ft	5000
Wellbore heat resistance coefficient, 1/(Btu/ft-D-°F)	0.008

Temperature Behavior

Grid selection. The temperature profile in the wellbore is affected by the fluid convection and the heat conduction between the wellbore and reservoir. Since the temperature behavior of the well depends on the temperature distribution around the wellbore, refined grid block scheme must be used. The first task of simulation study is to build a model that can capture the true temperature behavior in the wellbore with a reasonable computational cost. One approach to compromise the accuracy and the computational cost is to choose the model with an asymptotic temperature behavior. In this method, we refine the grid dimension of the model, starting from the coarse grid and study the temperature behavior during injection and shut-in. We chose the model, starting from which the more refinement of the grid scheme does not notably change the temperature behavior of the well.

The first model has uniformed grid block size in all direction: 100 ft in X direction, 100 ft in Y direction and 10 ft in Z direction. At time $t=0$, reservoir is at the initial geothermal temperature. Water is injected with constant rate for 3 days and shut in for 3 days (Fig. 3). The temperature along wellbore is reported from simulation at each time step during injection (Fig. 4) and shut-in (Fig. 5).

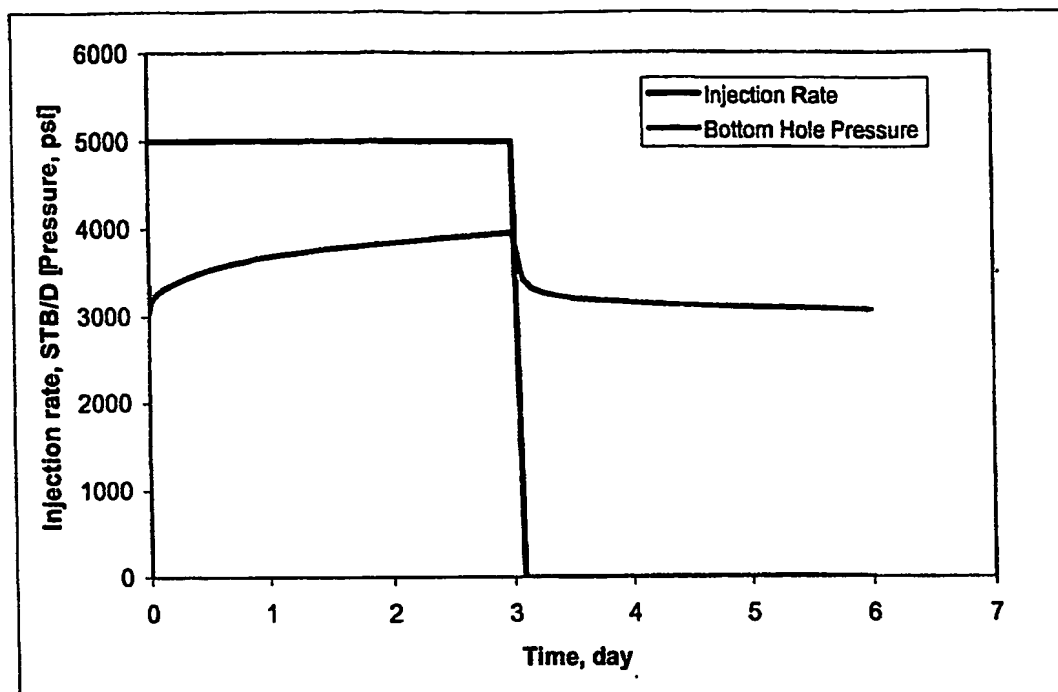


Fig. 3 – Well performance

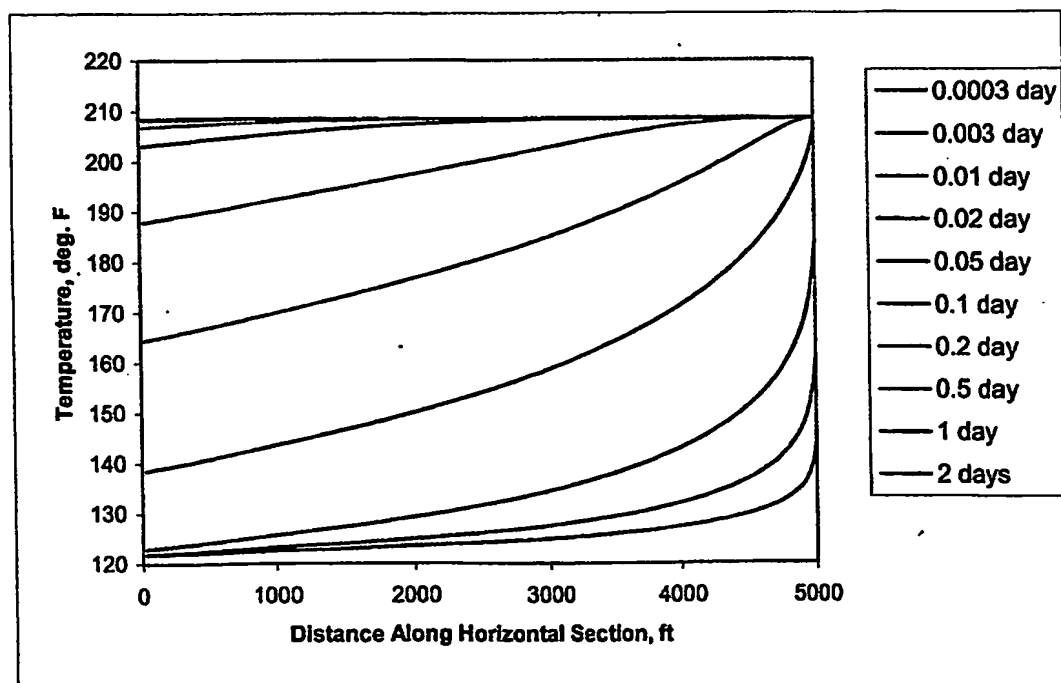


Fig. 4 – Temperature profile at different time during injection.

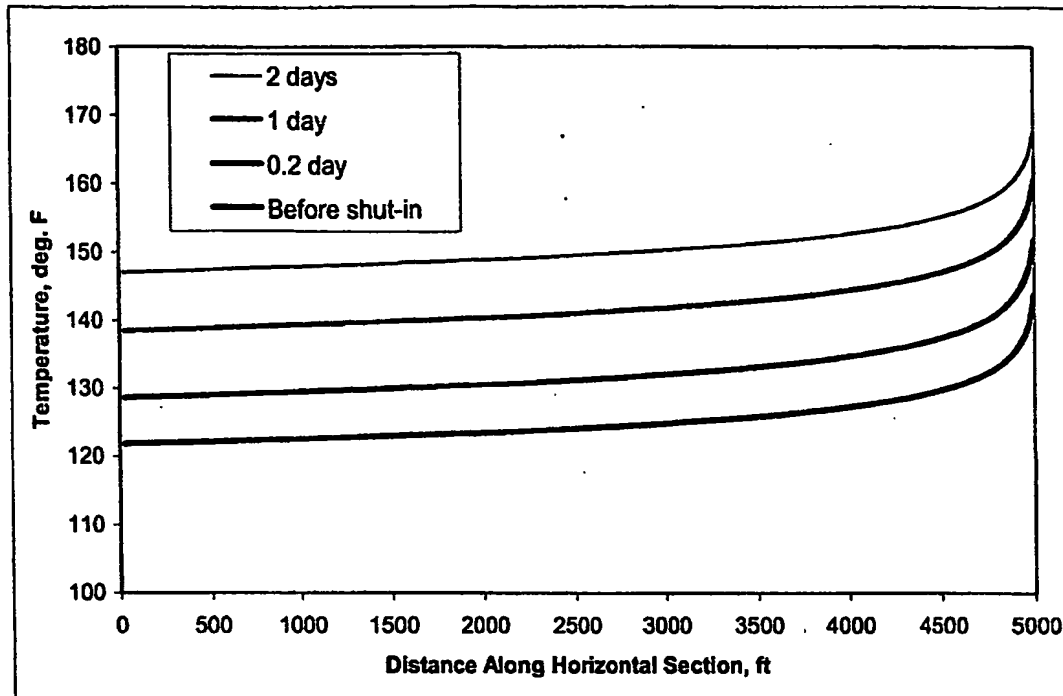


Fig. 5 – Temperature profile at different time during shut-in.

As I refined the grid size in Y and Z direction, the calculated temperature at well segment significantly changes, especially during shut-in. Figs. 6-7 show the temperature of the well segment at the middle of the well at different time during injection and shut-in for different grid refinement schemes. We can see that the temperature during shut-in changes very much as we refine the grid size around the wellbore. The temperature profile stabilizes as the size of the well block is 2 ft in Y, Z direction and exponentially increases outward (cases 4-6 on Fig. 7). The model, starting from which the temperature does not change with further refinement has 19 grid blocks in Y direction and 13 layers as shown in Table 3.

TABLE 3 – GRID BLOCK DIMENSION

Y, ft	1024, 512, 256, 128, 64, 32, 16, 8, 4, 2, 4, 8, 16, 32, 64, 128, 256, 512, 1024
Z, ft	22, 12, 8, 5, 4, 3, 2, 3, 4, 5, 8, 12, 22

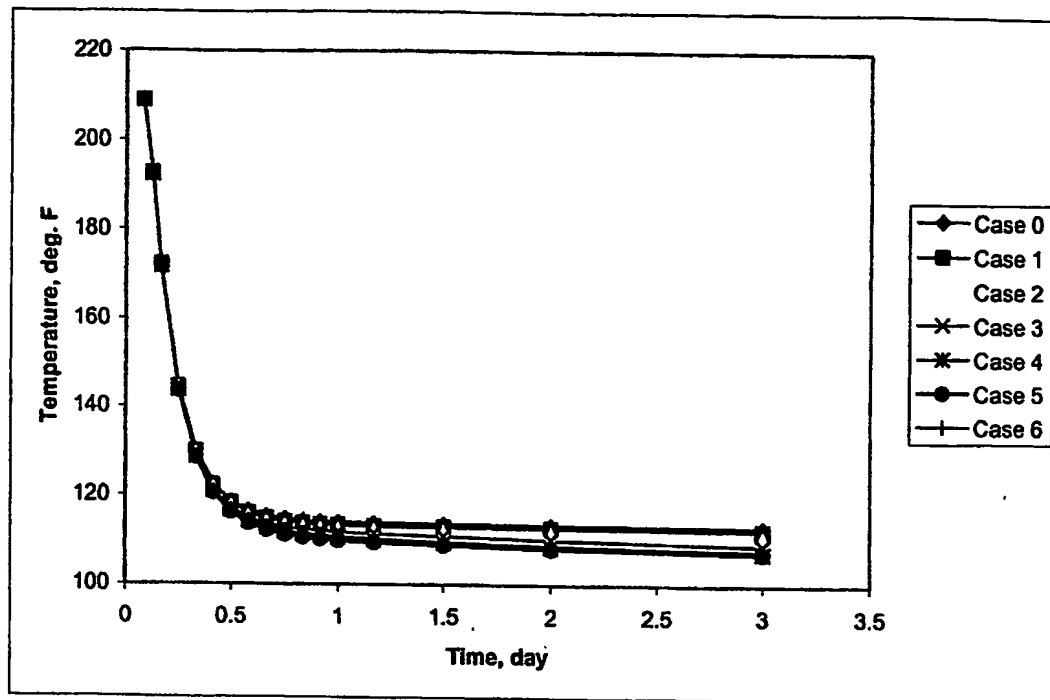


Fig. 6 – Temperature at the middle of the well during injection for different models.

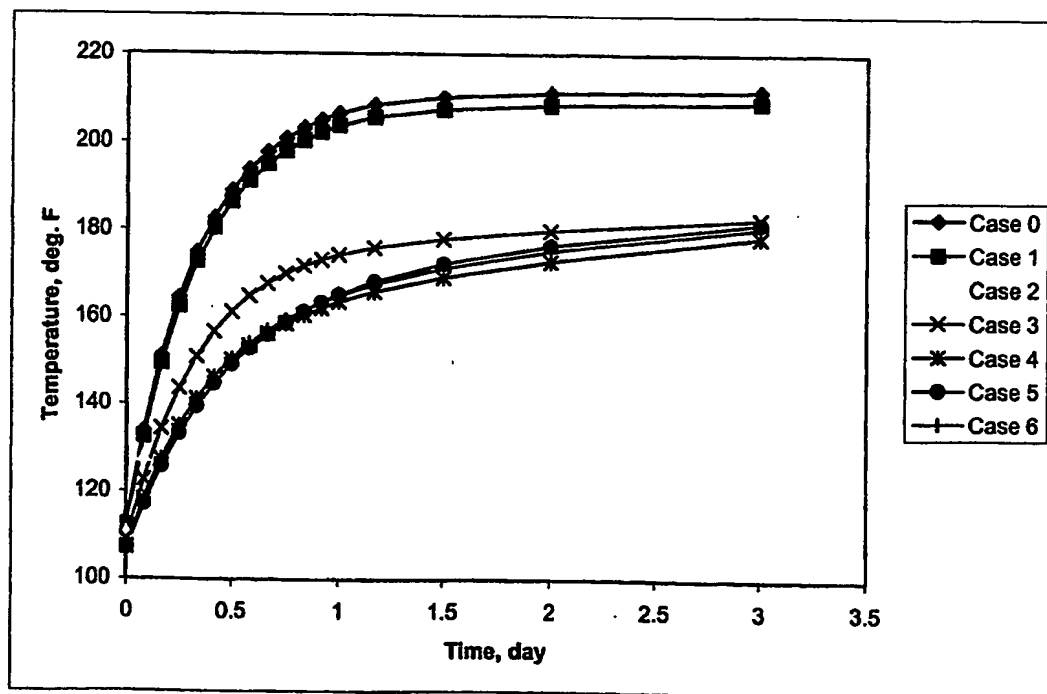


Fig. 7 – Temperature at the middle of the well during shut-in for different models.

To make sure that this model results a good temperature behavior with the change of rate and injection time, another model with excessive refined grid scheme in the Y and Z directions has been built. This model consists of 79 grid block in Y direction and 21 grid blocks in Z direction. This model and the model shown in Table 4 were run at two different injection rates (one is 5000 STB/D, another is 10000 STB/D). The temperature at the middle of the well shows very similar behavior with time (Fig. 9).

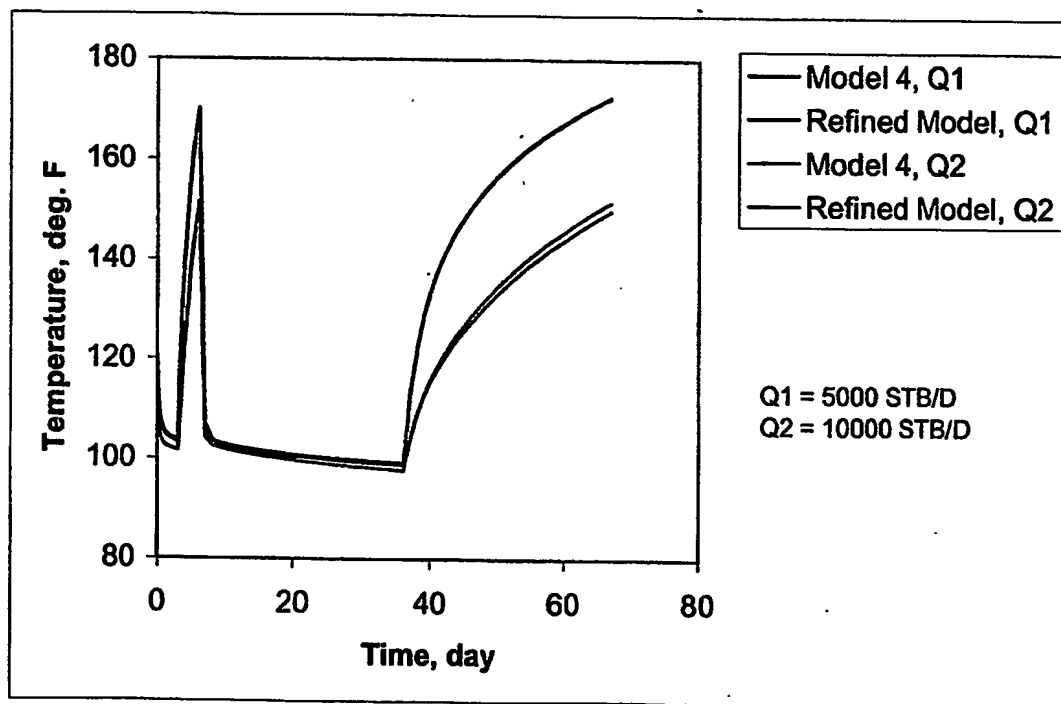


Fig. 9 – Temperature behavior at the middle of the well: selected model and refined model with different rates.

For homogeneous reservoir, the grid block size in X direction does not affect the simulated temperature in the wellbore after the temperature stabilized. But it does affect the calculated temperature along the wellbore at the early time of injection. For heterogeneous case, the grid block size in X direction is 25 ft - arbitrarily chosen to capture the heterogeneity along the wellbore.

The simulation model shown in Table 3 is used to gain insight of the temperature profile of the well. The well performance is similar to the one shown in Fig. 3. We will first look at the temperature behavior in the homogeneous reservoir, and then in the heterogeneous reservoir with different injection profile. In the real life, the temperature of the injected water at the heel of the well is a function of time. In order to accurately represent the real temperature behavior during early time of injection, we specified injection temperature according to the observed temperature from a well with similar configuration and injection rate (Fig. 10). This temperature of the injected fluid at the heel of the well during early injection time can be estimated using Ramey approach.

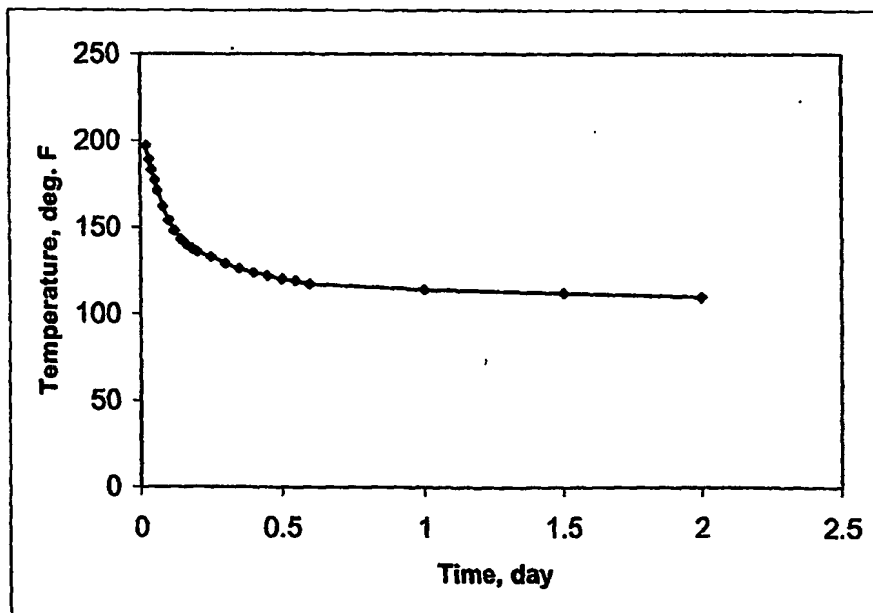


Fig. 10 – Injection temperature at the heel of the well.

Homogeneous reservoir. At very early time, we can observe the advancing of the injection front toward the toe of the well (Fig. 4). The higher the injection rate or the smaller the wellbore diameter is, the faster this front is advancing. With the injection rate of 5000 STB/D in homogeneous reservoir for the well having ID of 0.45 ft and length of 5000 ft, the simulation shows that the injection front will advance to 70% of the well length for 1 hr. At a later time, the temperature profile is stabilized with little change

along the wellbore. Time for the temperature to be stabilized depends on the heat thermal conductivity of the reservoir and the injection rate. For the injection rate used in this study, it takes 2 days for the temperature to be stabilized in a homogeneous reservoir.

During shut-in period, the temperature recovers in the wellbore. The rate and magnitude of the temperature recovery depend on total injection volume, the thermal conductivity of the well (Fig. 9). For the well in homogeneous reservoir, the rate of temperature recovery is constant for the whole length of the well (Fig. 5).

Heterogeneous Reservoir. Similarly to the temperature behavior in the homogeneous reservoir, the temperature profile can be considered as differently behaves in 3 periods. During early injection, the velocity of injection front depends on the distribution of injection flow along the wellbore. Fig. 11, 12 show the temperature profiles for two different distributions of the permeability along the wellbore. The temperature chest moves faster at the interval with low permeability and slower in the interval with high permeability.

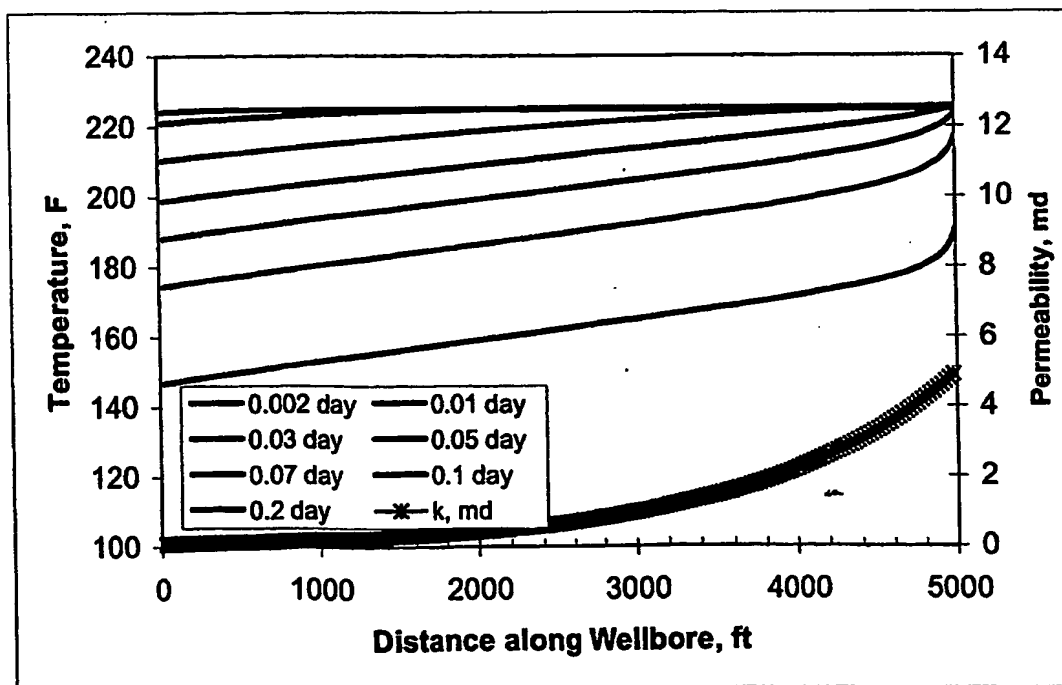


Fig. 11 – Temperature profiles at early time of injection: permeability increases along wellbore.

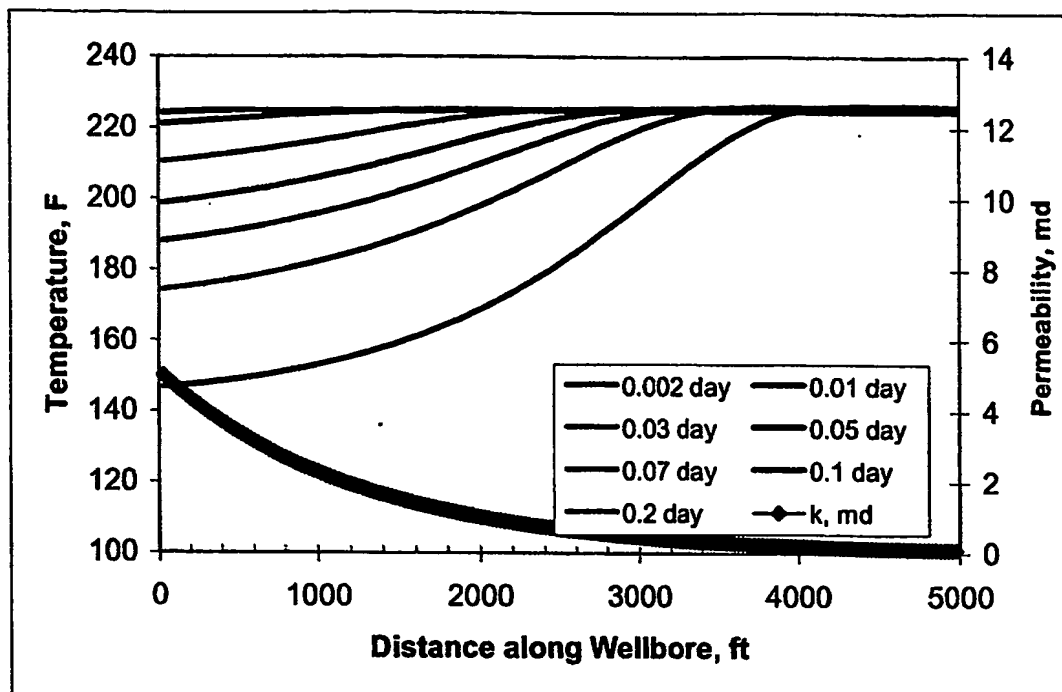


Fig. 12 – Temperature profiles at early time of injection: permeability decreases along wellbore.

At a later time, temperature profile only bears the information of the injection profile for the end of the well. If the injection rate at the end of the well is high, the temperature profile is flat (Fig. 13). If the injection rate at the end of the well is low, the temperature profile is curving upward (Fig. 14).

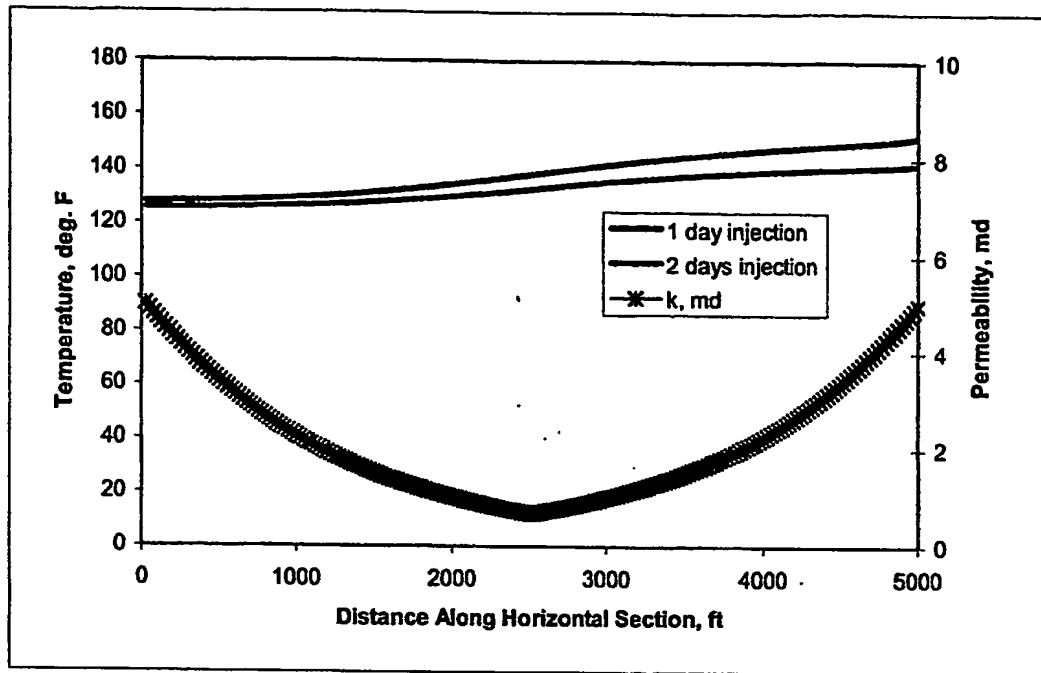


Fig. 13 – Stabilized temperature profile for the case with high injection rate at the tip of the well.

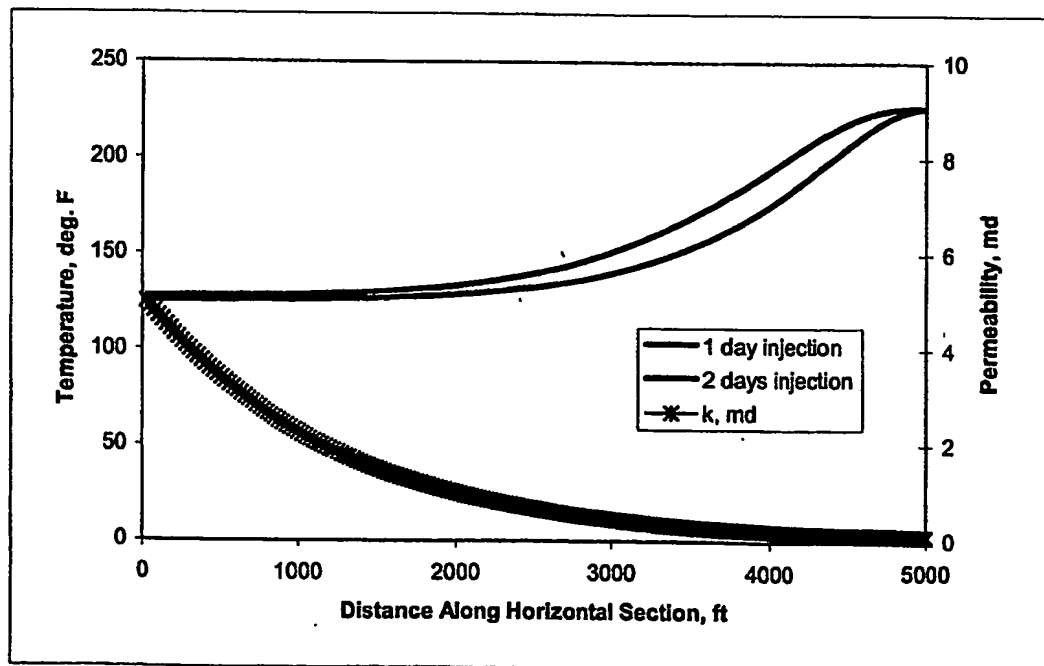


Fig. 14 – Stabilized temperature profile for the case with low injection rate at the tip of the well.

For all cases of the permeability distribution, the shut-in temperature profiles correlate with the injection profile along wellbore (Figs. 15-17). The rate and the magnitude of the temperature recovery are higher in the interval with small injection rate than in the interval with high injection rate.

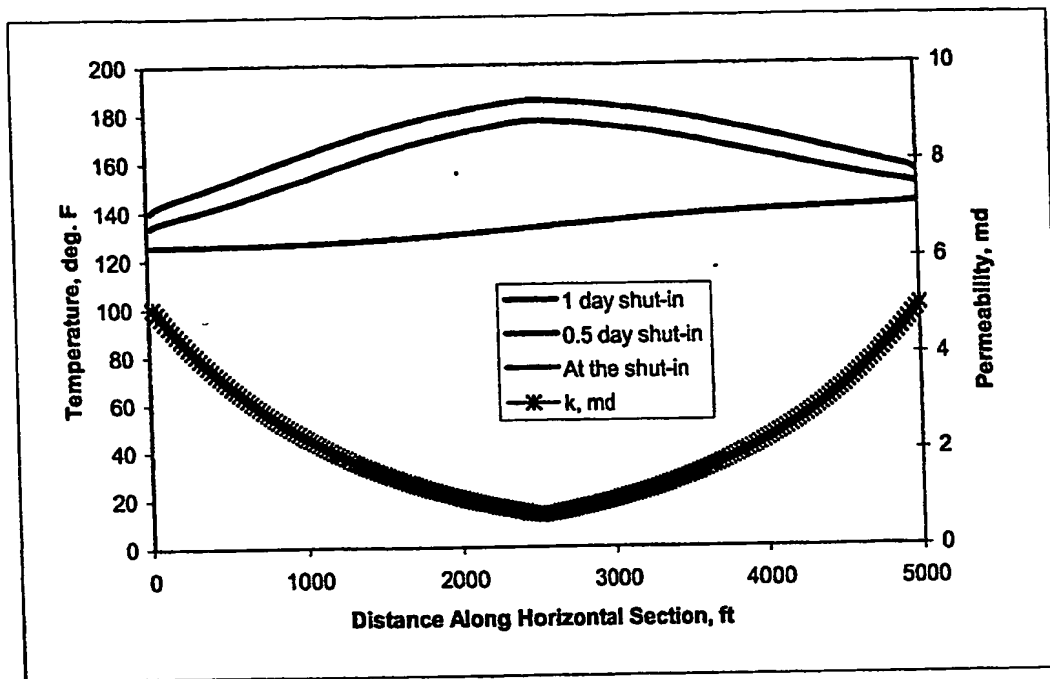


Fig. 15 – Temperature profile during shut-in, low permeability at the middle.

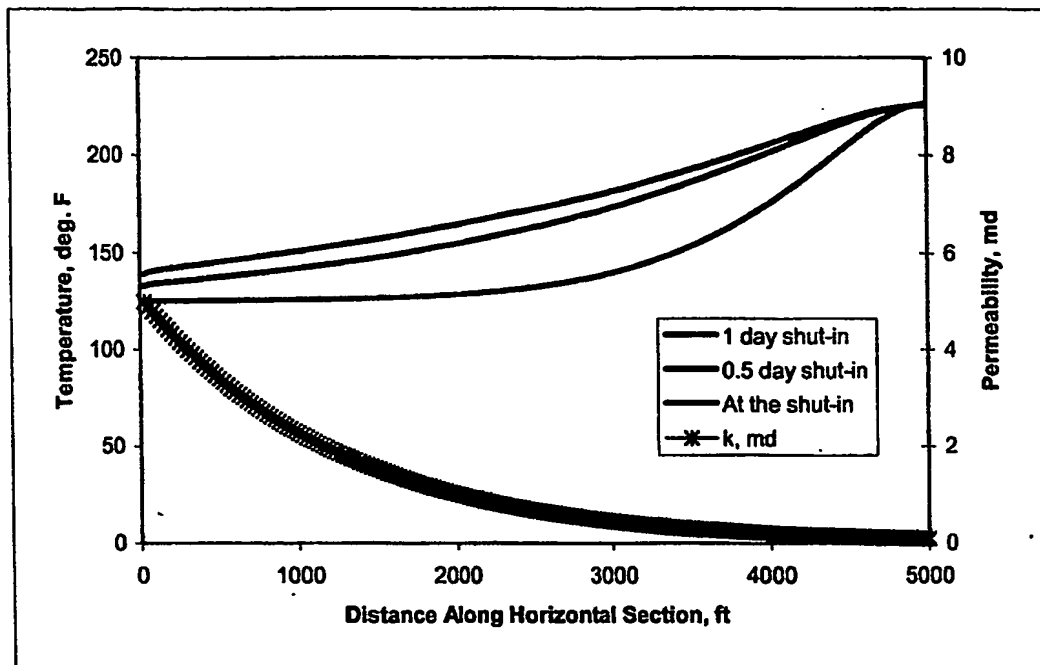


Fig. 16 – Temperature profile during shut-in, low permeability at the tip.

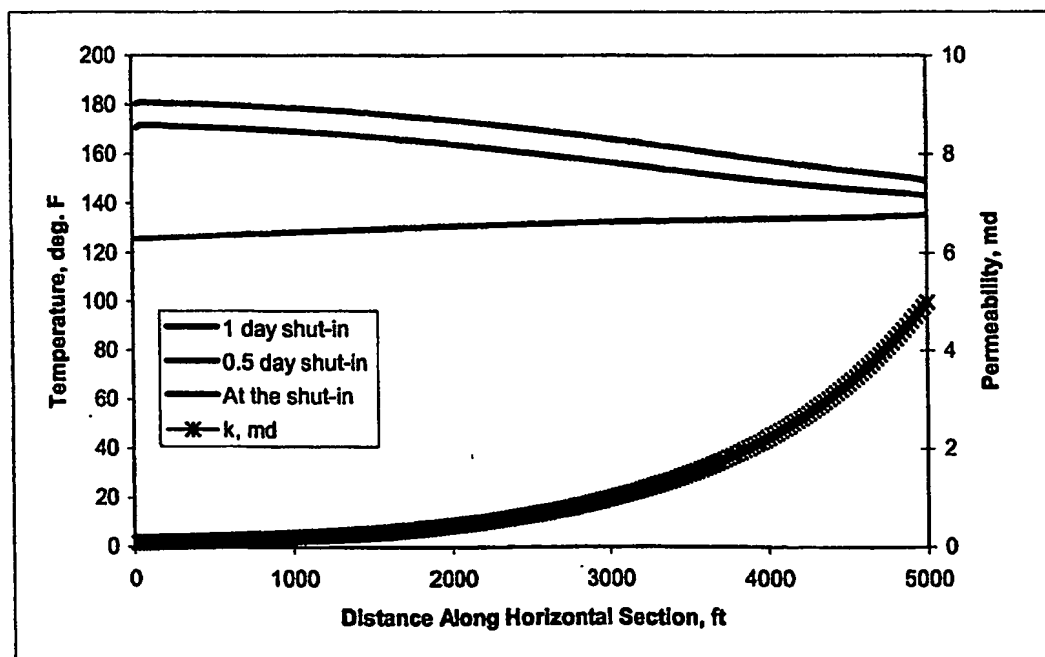


Fig. 17 – Temperature profile during shut-in, low permeability at the heel.

Effect of Rate. The high injection rate case differs from low injection rate case in 2 areas: it accelerates the rate of cooling in the wellbore due to larger volume of cool water being injected into reservoir; and it creates higher pressure drop in the wellbore or change the flow profile along wellbore. Three cases have been run to study the effect of the rate and pressure drop along the well bore on temperature profile: one with injection rate of 5000 STB/D, one case with injection rate of 15000 STB/D; and the third case with injection rate of 15000 STB/D and reduced wellbore diameter (from 0.45 ft to 0.35 ft). The total pressure drop from the heel to the toe of the well is 4, 50 and 200 psi respectively. Fig. 18 compares the injection temperature profile for the first two cases.

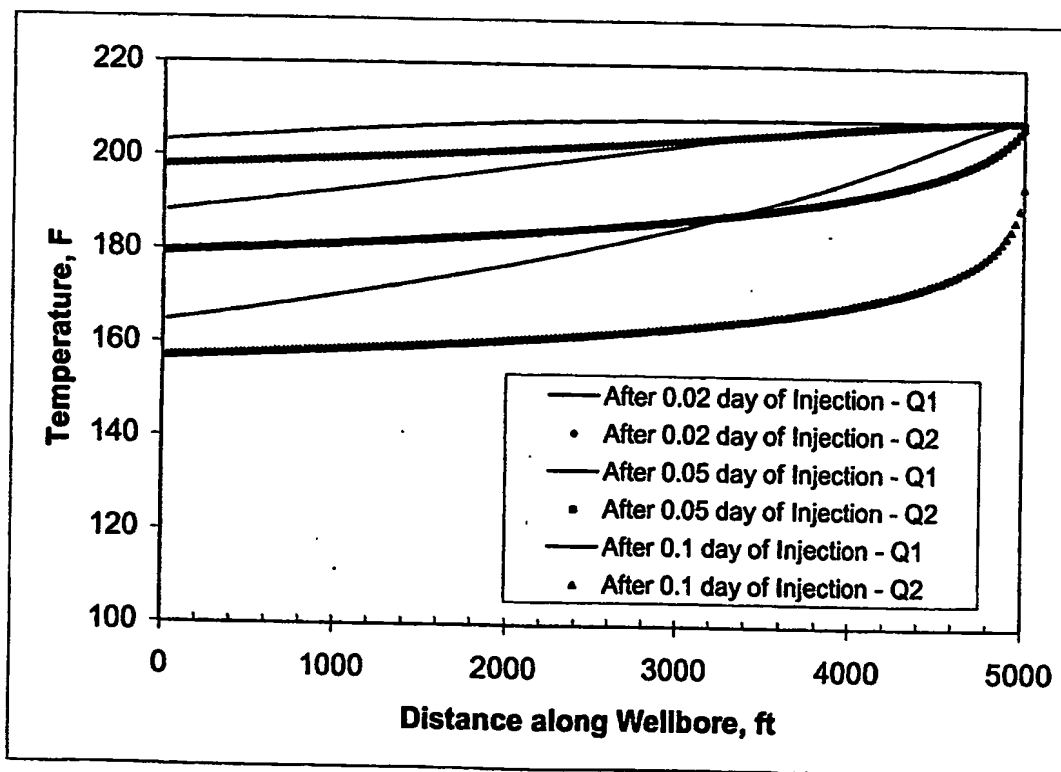


Fig. 18 – Temperature profile during early injection: different injection rate.

The only difference in the temperature profile is that the temperature profile for high injection rate quickly stabilizes along the wellbore. The injection profile is almost constant for the case with small pressure drop in wellbore. In the case of high pressure drop in the wellbore, the injection profile slightly decreases along the wellbore

(maximum difference of up to 10% - Fig. 19). During shut-in, the magnitude of the temperature recovery is very small in the case of higher injection rate and it does not capture the change of the injection profile along the wellbore (Fig. 20). It is worth noting that the shape of injection profile along the wellbore is different, depending on the position of the well in the X direction. The injection profile would have the U shape if the well locates far from the edge of the reservoir. The result implied by the temperature behavior as shown in Fig. 20 is that temperature profile may not capture the small variation of the injection profile along the wellbore.

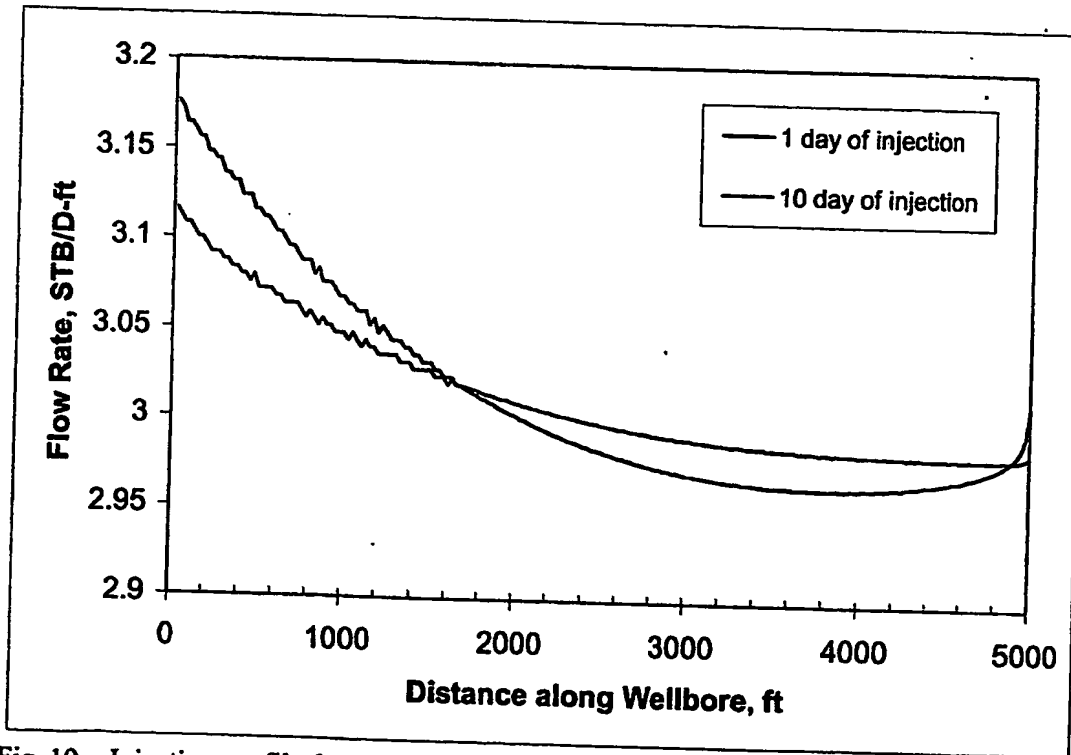


Fig. 19 – Injection profile for the case of high pressure drop along the wellbore ($Q = 15000$ STB/D).

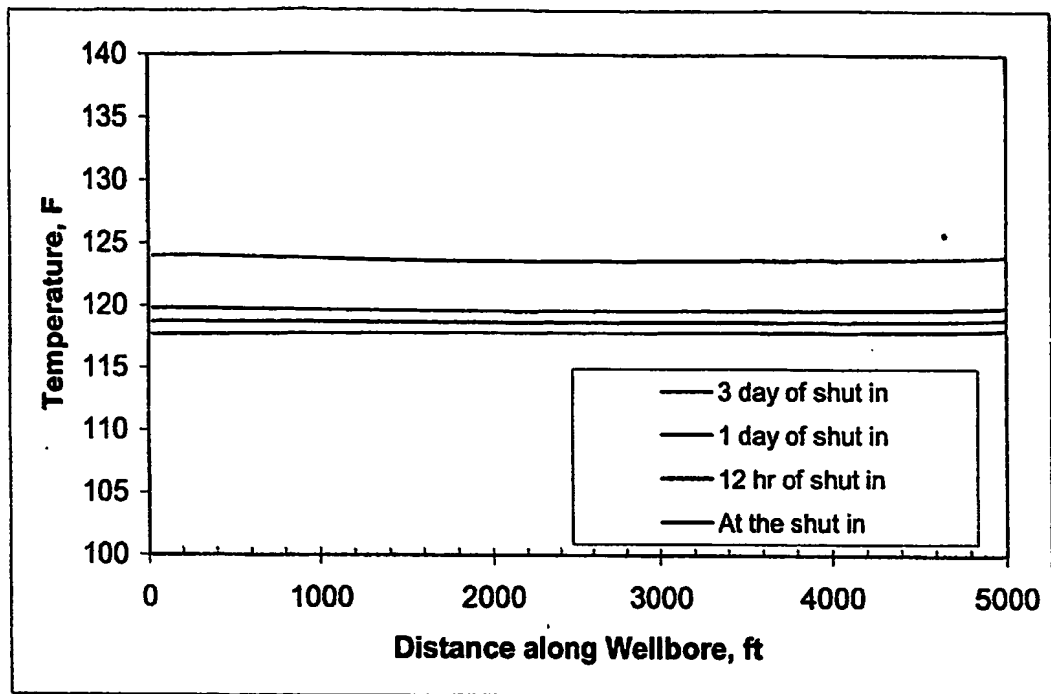


Fig. 20 – Temperature profile during shut-in: injection rate $Q = 15000$ STB/D

For the model with high pressure drop in the wellbore, a notable fluid redistribution may occur in wellbore after shut-in (Fig. 21). This phenomenon may affect the temperature profile along the wellbore. As we can see, the region with higher injection rate will have fluid coming back into wellbore during shut-in.

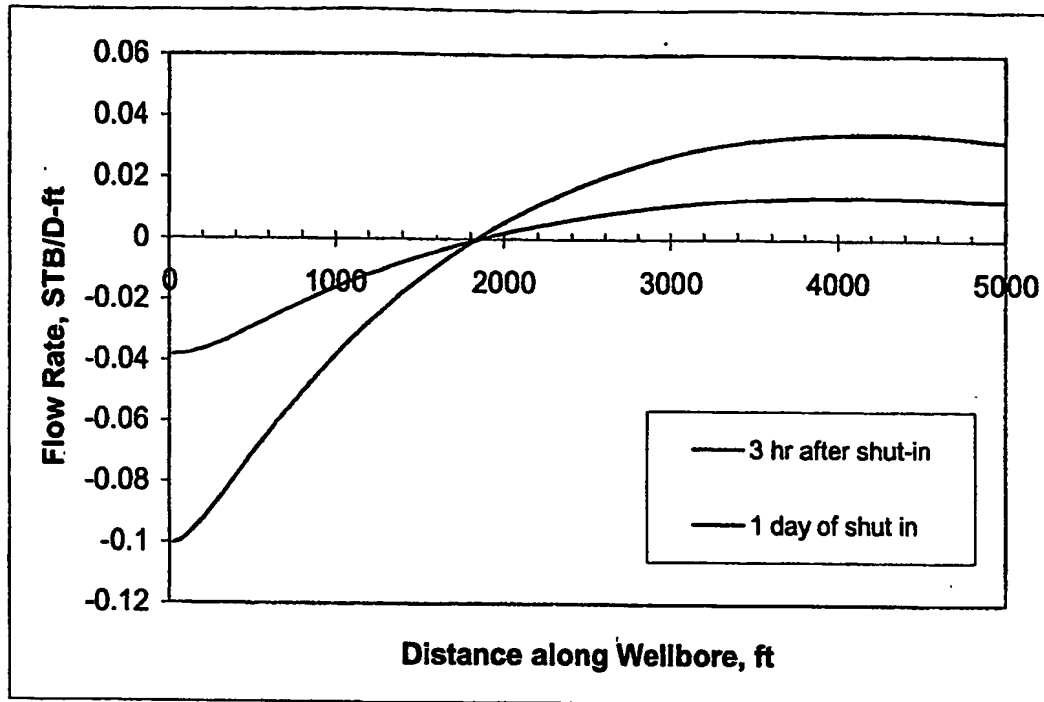


Fig. 21 – Flow rate to/into reservoir after the shut-in (negative value means flow from reservoir, positive means flow into reservoir)

Conclusions

- The selection of the grid block size of the model has great effect on the temperature behavior in the wellbore. The grid block size is as small as 2 ft around the wellbore is required for simulating the temperature profile of the well.
- Compare to the vertical well, the temperature profile during early injection time is controlled by the injection profile and injection rate. .
- Temperature profile at late injection time may give only qualitative information of the injection profile.
- Temperature profile during shut-in is controlled by injection profile, thermal conductivity of the reservoir, injection rate and injection time.

Interpretation Methods of Temperature Profile

This section describes the interpretation technique and their application. Three interpretation techniques are considered: one for interpreting the temperature profile during the early injection period based on the movement of the water in the wellbore; one for shut-in temperature data based on the source and sink method for temperature build up in the wellbore; one for shut-in temperature data based on the assumption of two temperature region in the reservoir at the shut-in.

Analysis of Injection Data

In the previous section, the temperature behavior has been studied for different flow profile. There is no interpretation technique for interpretation of the temperature during injection for vertical well. Because of the short wellbore length at the injection interval, temperature in wellbore quickly stabilized to the temperature of the injected water. For horizontal well, however, if the temperature along the wellbore before the injection is known, the temperature profile can be used to estimate the flow profile, providing that enough contrast between wellbore temperature and the temperature of injection fluid exists. Assuming that we can determine the speed at which water moves inside the wellbore from the temperature profile, we can determine the flow profile at any interval along the wellbore as:

$$q_i = \frac{1}{(x_i - x_{i-1})} \left[Q - \frac{\pi D_i^2}{4} v_i - \sum_1^{i-1} q_j (x_j - x_{j-1}) \right], \dots\dots\dots(1)$$

where the subscript i denotes the location of interest, j is running from the heel of the well to the location of interest. As we can see from the equation, the accuracy of injection profile depends on the accuracy of the total injection rate, the wellbore ID, and the position of the injection front in the wellbore.

Analysis of Shut-In Data

Nowak method. Nowak¹ proposed the method for determining the injection profile using the approximation of the source and sink method for temperature build-up in the vertical wellbore. This results to a linear relationship between injection intake rate and the temperature recovery along the wellbore at any time t after shut-in:

$$\Delta T_i = \frac{Q_i}{4\pi K} \ln \frac{t_{inj}}{t_{inj} + t}, \dots\dots\dots (2)$$

where ΔT_i is the temperature difference between the reservoir temperature and the temperature at time t after shut-in; Q_i is the total heat transfer in the reservoir, which can be assumed proportional to the product of injection rate and injection time $q_i t_{inj}$. Subject to a constant injection rate, the Eq.2 can be expressed as:

$$Q_{inj} = A \sum_{i=1}^N L_i t_{Di}, \dots\dots\dots (3)$$

This equation is used in analysis the injection profile along the wellbore as followed:

- 1- The shut-in temperature curve in the region of non-permeable strata above the injection interval is extrapolated through the injection interval for determining the reservoir temperature.
- 2- The area between the actual curve and the extrapolated curve is determined.
- 3- For each unit depth, the fraction of the total injection rate is the same as the fraction of the area between two curves over the total area.

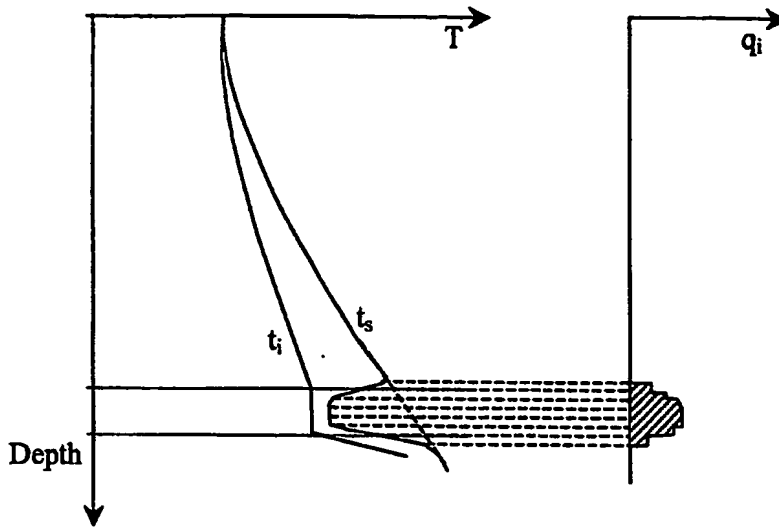


Fig. 22 – The Nowak method for injection flow profiling.

The Nowak method does not account for the heat transfer in the vertical direction. Thus, the transition zone between injection interval and impermeable strata can be erroneously interpreted (Fig. 22). Cocanower *et al.*³ proposed a method for better determining the boundary between formations. This method used temperature profile at early after shut-in to calculate the temperature decay coefficient and used this coefficient to calculate the shut-in temperature at a later time. However, this method is affected by the fluid redistribution in the wellbore at early time after shut-in as discussed in previous section and hence will not be considered here.

New alternative method. Assuming that the temperature distribution in the reservoir at the shut-in has the shape of two distinctive regions, one with average reservoir temperature, one with the temperature of the wellbore at the shut-in (Fig. 23), the temperature behavior at the wellbore can be expressed as followed:²

$$T_D = \frac{1}{2\alpha} e^{-\frac{r^2}{4\alpha}} \int_0^{R_c} \zeta e^{-\frac{\zeta^2}{4\alpha}} I_0\left(\frac{r\zeta}{2\alpha}\right) d\zeta, \dots\dots\dots (4)$$

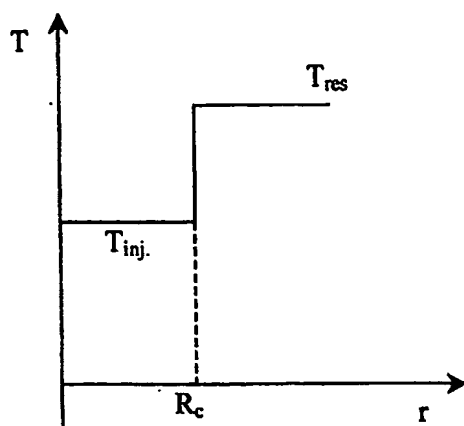


Fig. 23 – Assumption for the temperature distribution in the reservoir: two temperature regions at the shut-in.

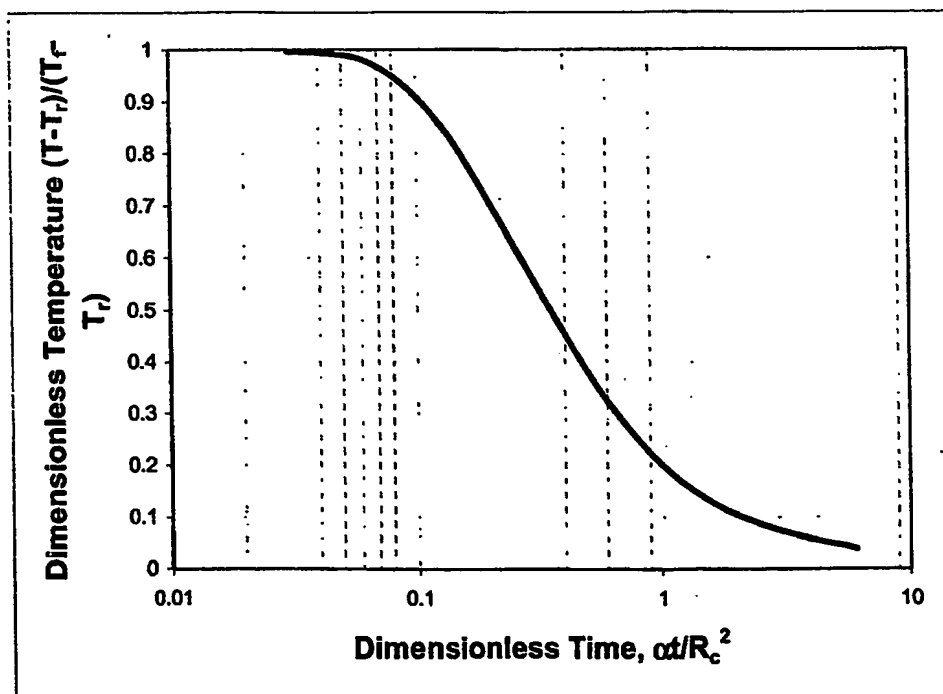


Fig. 24 – Solution to the temperature behavior at the well in the reservoir as shown in Fig. 23.

The solution of this equation is shown in Fig. 24 in term of the dimensionless temperature and dimensionless time. Assuming that the temperature front is the same as the saturation front, this solution can be used to relate the total injection water into each interval and the radius of the temperature front as followed:

$$q_i t_{inj} = \pi R_{ci}^2 \phi (1 - S_{iw}) , \dots\dots\dots (5)$$

Or, in term of total injection rate:

$$Q_{inj} = A \sum_{i=1}^N L_i t_{Di} , \dots\dots\dots (6)$$

This equation is used to estimate the flow profile along the wellbore with t_{Di} determined from Fig. 24. The different between this method and Nowak method is that it related injection rate to the temperature in the exponential, instead of a linear, relationship.

The procedure for estimating the injection profile is as followed:

- 1- Determine the initial temperature of the formation T_r . For horizontal well, it is the initial temperature of the reservoir.
- 2- The dimensionless temperature for each interval is determined from the temperature log and the reservoir temperature: $T_d = (T_r - T_s) / (T_r - T_{inj})$.
- 3- For each unit depth, determine the dimensionless time t_D from Fig. 24.
- 4- This dimensionless time for each interval along wellbore is used in Eq. for estimating the correction coefficient A. The flow rate into reservoir for this interval is: $A * t_{Di}$.

Both aforementioned methods for shut-in temperature data determine the injection profile based on the assumption of known reservoir temperature and, small radius of the injection front in the reservoir, and no heat transfer in the X direction. For the well with long injection time or unknown well history, when these assumptions are no longer valid,

the result of analysis may be suffered. In the next section, these methods of estimating the injection profile will be examined on the actual well data. The estimated flow profile from each method will be compared to the simulated flow profile to see which one performs best.

Application to Safah-200 Water Injection Well

This section examined the temperature profile of the actual water injection well. The numerical simulation model is built to reproduce the measured temperature data. The injection profile from simulation is used to compare with the injection profile, estimated by using the analytical methods. The model is also used to assess the applicability of analytical method at different times of the well life.

Well Performance and Temperature Behavior

This well is completed in a low permeability micritic limestone reservoir. The reservoir fluid is light (42 deg. API), low viscosity (0.4 cp). Average porosity is 22%. The permeability of the reservoir is less than 5 md. The reservoir thickness is of 100 ft -130 ft.⁸ Fig. 25 shows the schematic of the completion of the well.⁹ In the horizontal section of 5400 ft, a stinger of 2"7/8 is used to convey DTS along the wellbore. The well is under injection with the rate of 4500 STB/D for 14 days, following by 1 day of shut-in and 3 hr of re-injection (Fig. 26). The temperature data is available for the shut-in period and for 3 hr of injection that followed.

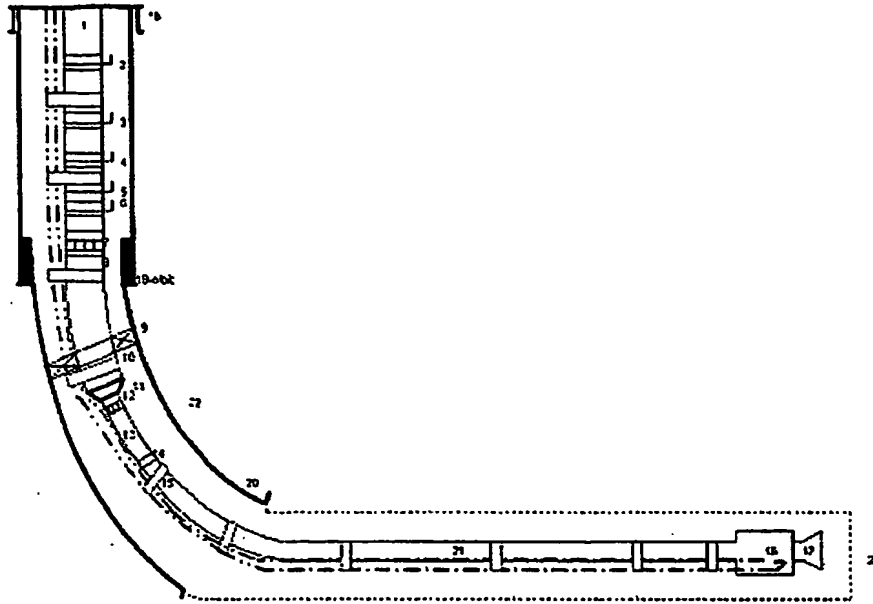


Fig. 25 – Well completion: blue line represent the fiber optic line.

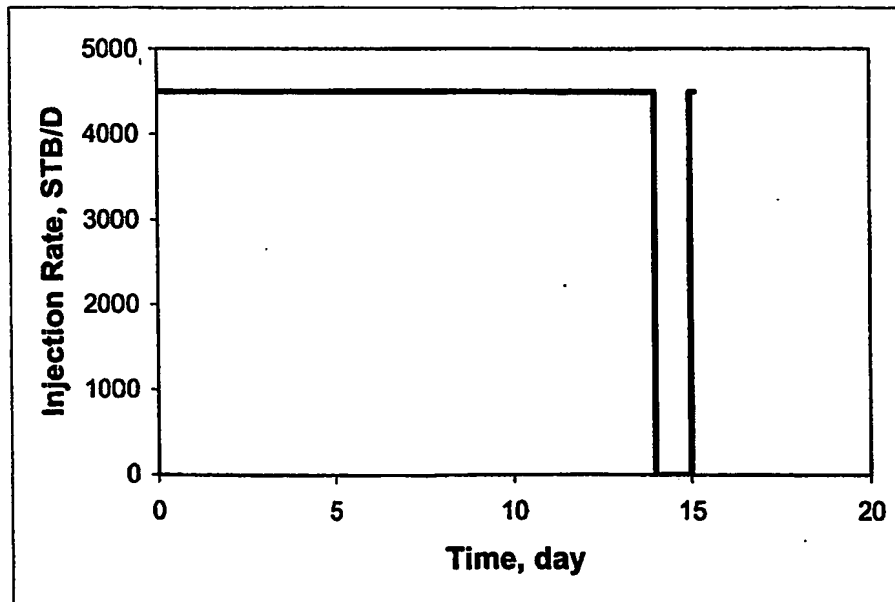


Fig. 26 – Well injection history.

After 14 days of injection, the temperature in the well shows that the first half of the well length has the almost constant temperature. Temperature at the second half is gradually increases to the temperature of the reservoir. The temperature profile is very similar to

that for heterogeneous reservoir, where permeability is gradually decreases toward the well (Fig. 12). During shut-in, temperature increases at different rate along the wellbore (Fig. 27). We will applied the analytical method to estimate the injection profile from temperature profile during shut-in. One important observation is that during shut-in, the temperature at above casing shoe is increases at a higher rate, compared to the part of wellbore below casing shoe. After one day of shut-in, the temperature difference at casing shoe is about 40 F. When the injection is resumed, this portion of hotter water is pushed along the wellbore (Fig. 28). The water temperature is decreasing partly due to the water going into formation, partly because of the heat loss while moving toward the toe. The movement of this hot slug of water along the wellbore can be used to estimate the injection profile along the wellbore in the same manner as described in previous section for temperature during early injection.

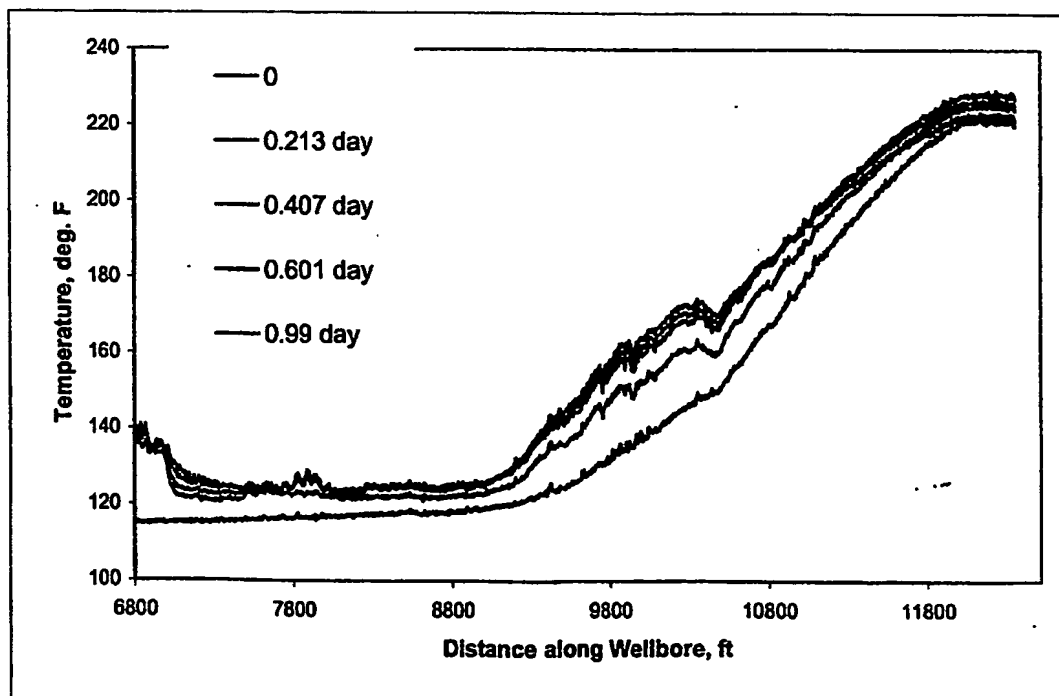


Fig. 27 – Temperature profile of the well during shut-in.

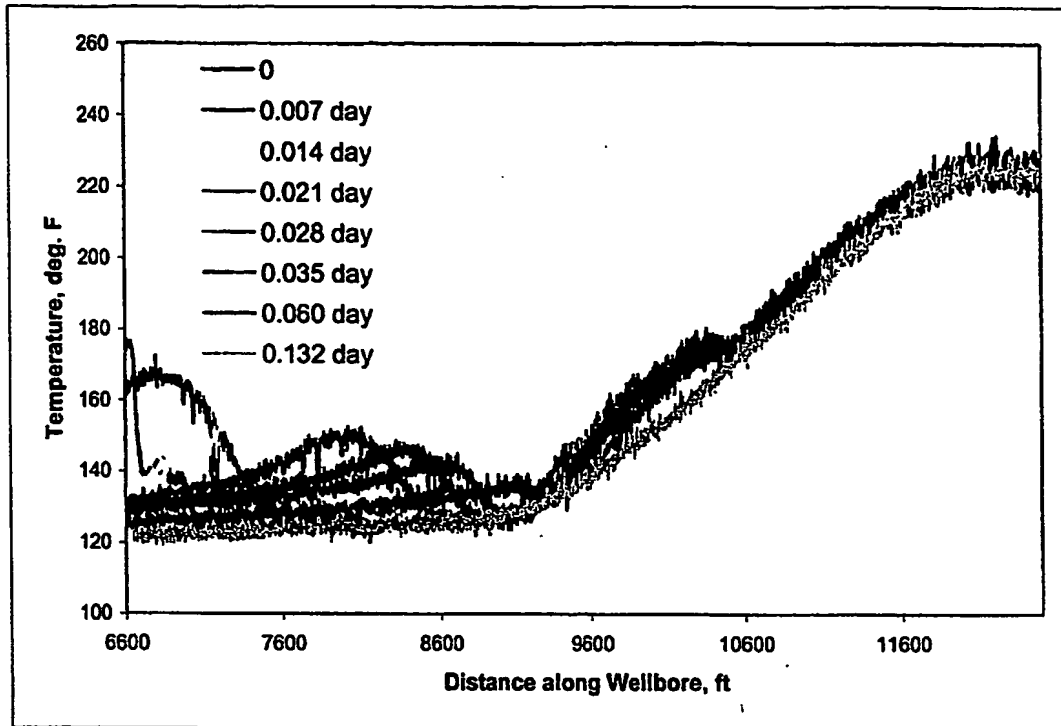


Fig. 28 – Temperature profile during three hours of re-injection.

In the next section, we present the result of the injection profile estimation from three analytical methods as described in the previous section for temperature data during shut-in and re-injection.

Shut-in Analysis

Nowak method. Following the procedures mentioned in previous section, the flow profile is estimated from temperature data during shut-in. Fig. 30 shows the injection profile estimated from the temperature at the end of the shut-in period by using Nowak methods. Note that for constant initial reservoir temperature, the injection profile is just the curve of $(T_r - T_i)$, scaled down so that the area under the curve is the total injection rate.

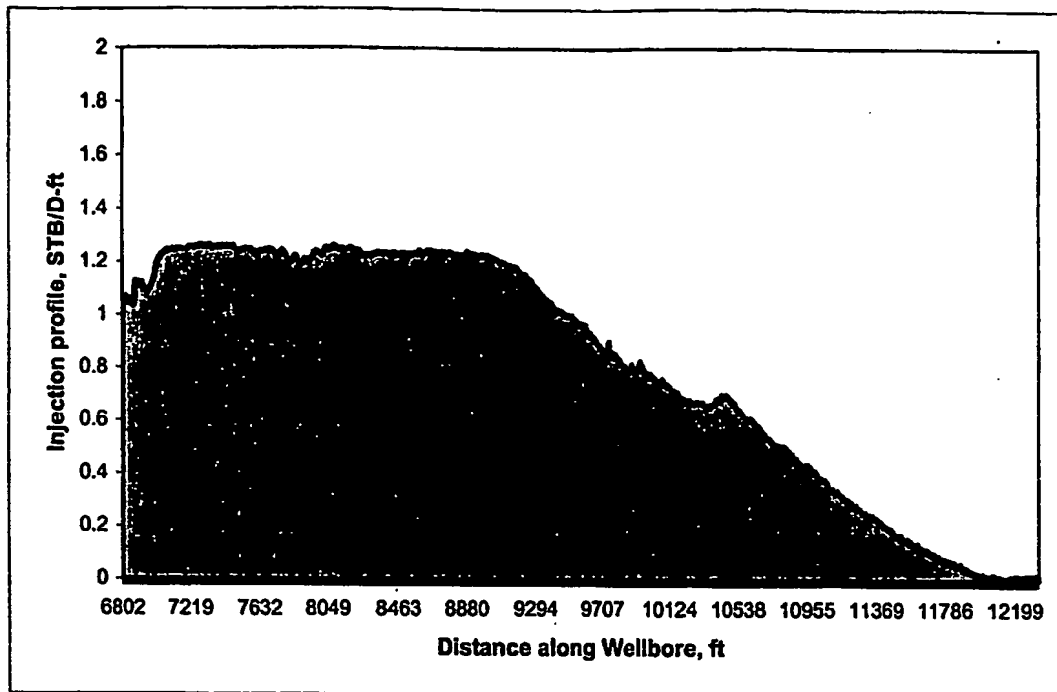


Fig. 30 – Injection profile from Nowak method.

New method. Assuming the initial reservoir temperature of 226 F, the dimensionless temperature at two different shut-in times are shown in Fig. 31. We can see that around the tip of the well, the dimensionless temperature becomes unstable because the temperature at the shut-in is closed to the reservoir temperature. Any drift or noise in temperature may cause the t_D become unreasonable large or small.

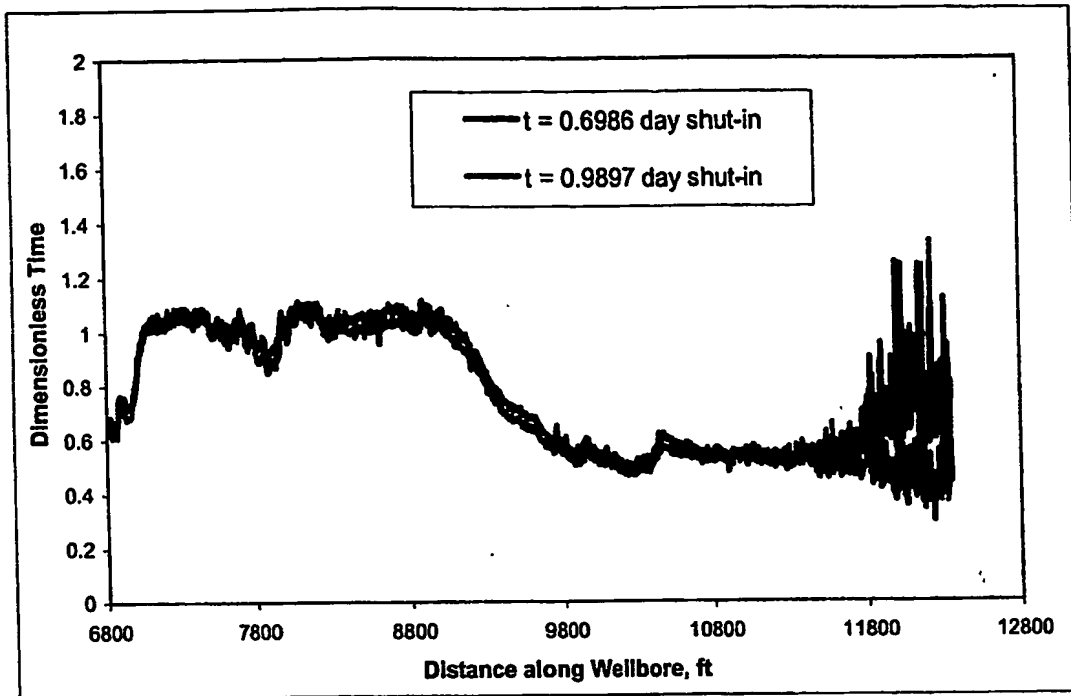


Fig. 31 – Dimensionless time at two different shut-in times.

We can overcome this problem by combining the magnitude of the temperature recovery into account of T_D . Multiplying the T_D with the Nowak temperature ($T_r - T_s$) will dampen the effect of noise in the region with very small temperature difference. The injection profiles using these normalized T_D are shown in Fig. 32.

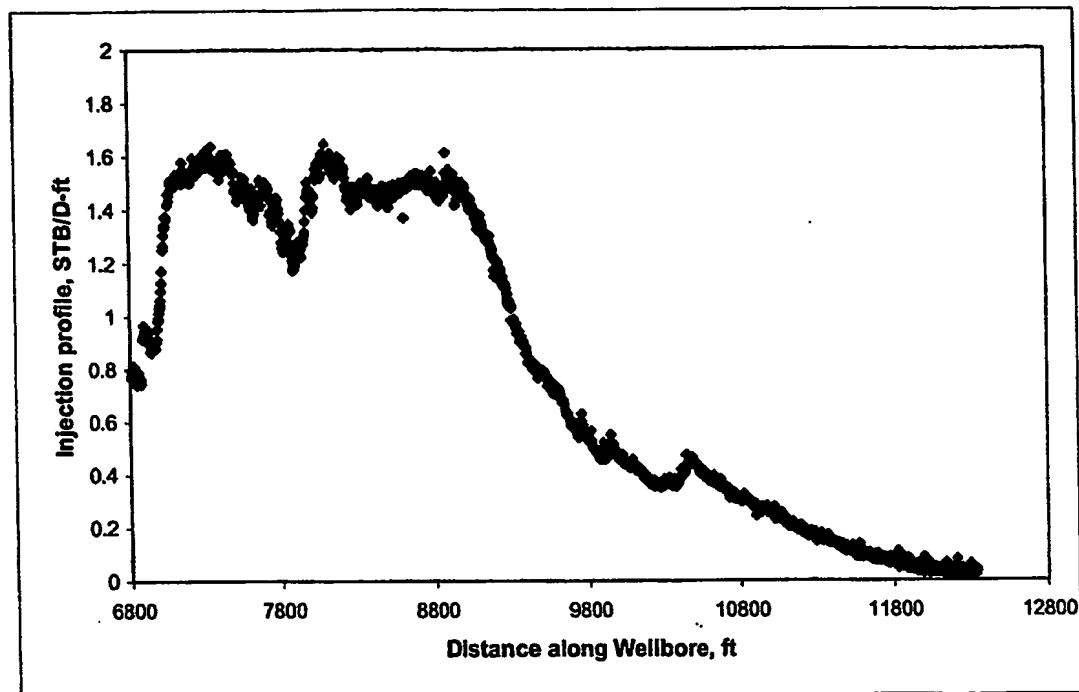


Fig. 32 – Injection profile using new method.

Injection Analysis

Assuming that the position of the slope of the temperature curve in the front of the transition zone represents the injection front (Fig. 33), the velocity of the water inside the wellbore is shown in Fig. 34. The noise in the velocity data indicates that the position of the injection front in the wellbore is sensitive to the noise in the temperature data. From Eq. 1, it is clear that the accuracy in determination of injection profile is affected by the *in-situ* total injection rate, the accuracy of front position from temperature data, and wellbore diameter. Wellbore ID can be assumed to be constant in well with liner completion. The fluctuation of the total injection rate and the accuracy of the injection front from temperature data are the major factors that affect the result. Because of the noise in temperature data, this interpretation method is difficult to be done automatically.

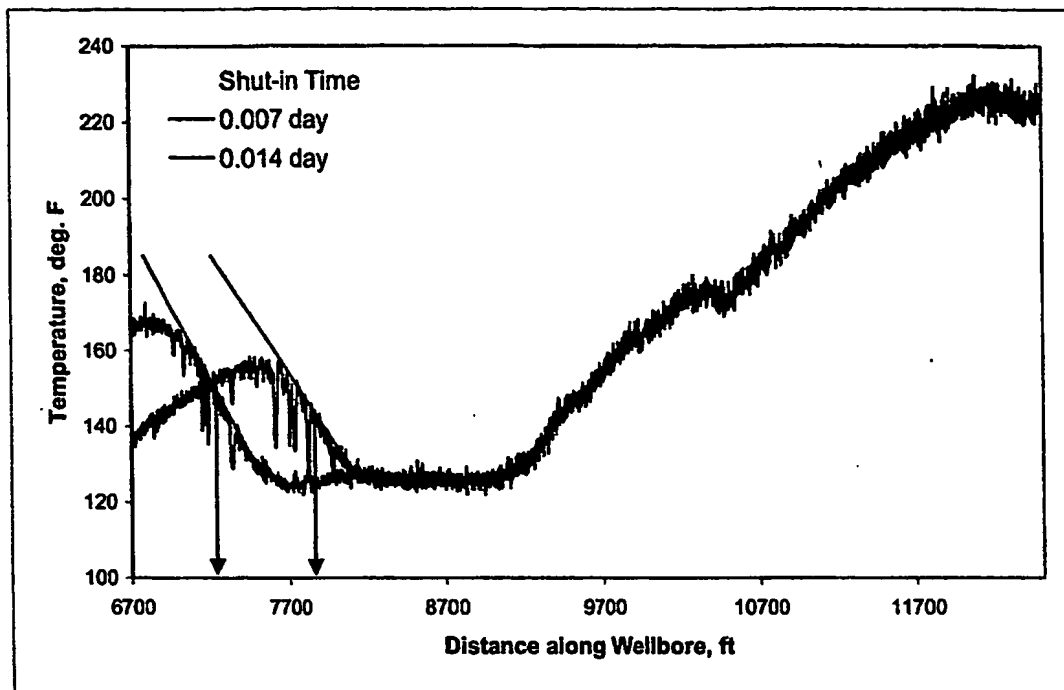


Fig. 33 – Example of injection data analysis.

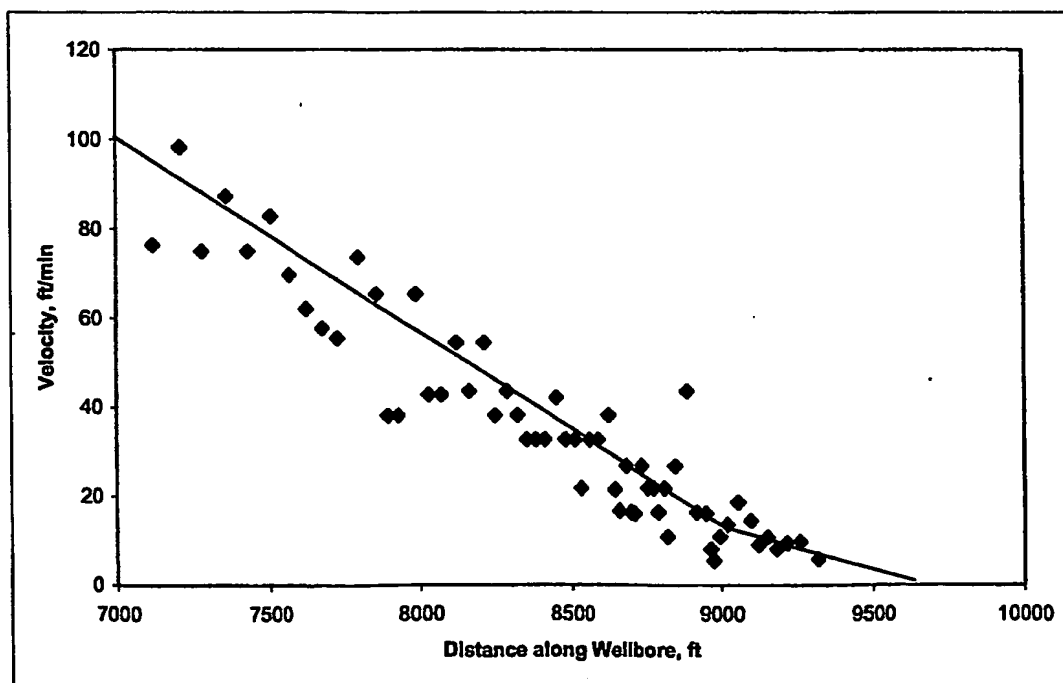


Fig. 34 – Velocity of the water in the wellbore, determining from temperature profile during early re-injection

Assuming constant well ID and constant injection rate, the fluid velocity can be represented by a best-fit line (or lines) as shown in Fig. 34. The injection profile can be estimated from that fluid velocity as is shown in Fig. 35.

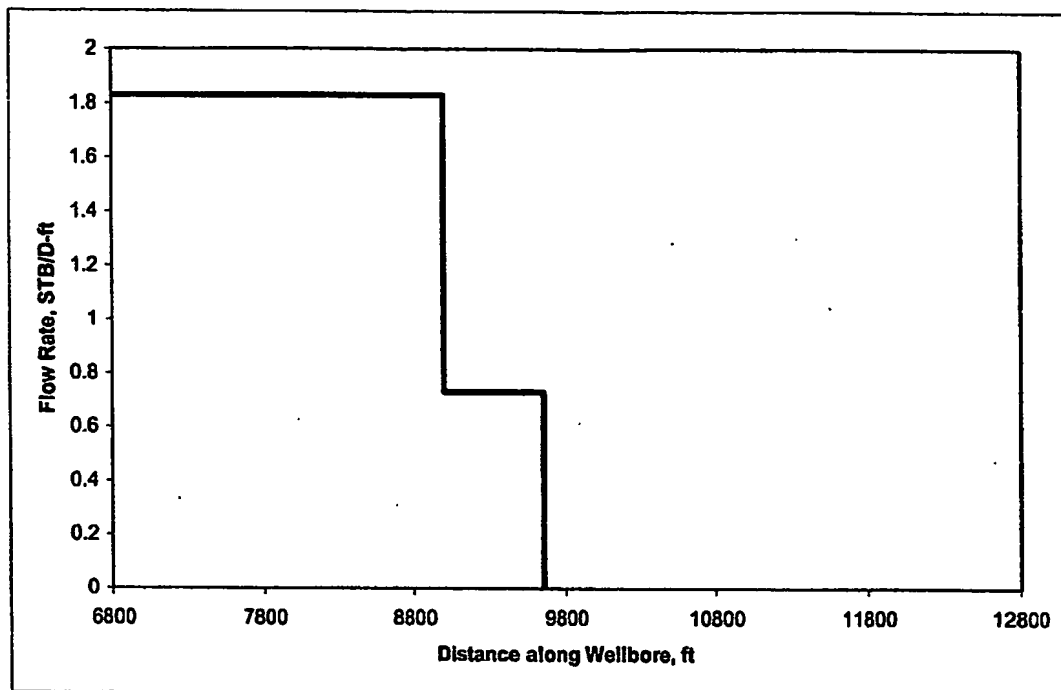


Fig. 35 – Injection profile for the data in Fig. 34 from temperature during injection.

The estimated injection profiles from all three methods are shown in Fig. 36. As we can see, all methods show similar feature of the injection profile: the first half of the well contributes most of the injection rate of the well, while the second half of the well contribute small portion of the injection rate. The interpretation method for shut-in data gives more detailed feature of injection profile than the method for injection data does. For shut-in temperature data, the new method gives the injection profile with higher contrast between two parts of the well, compared to the Nowak method.

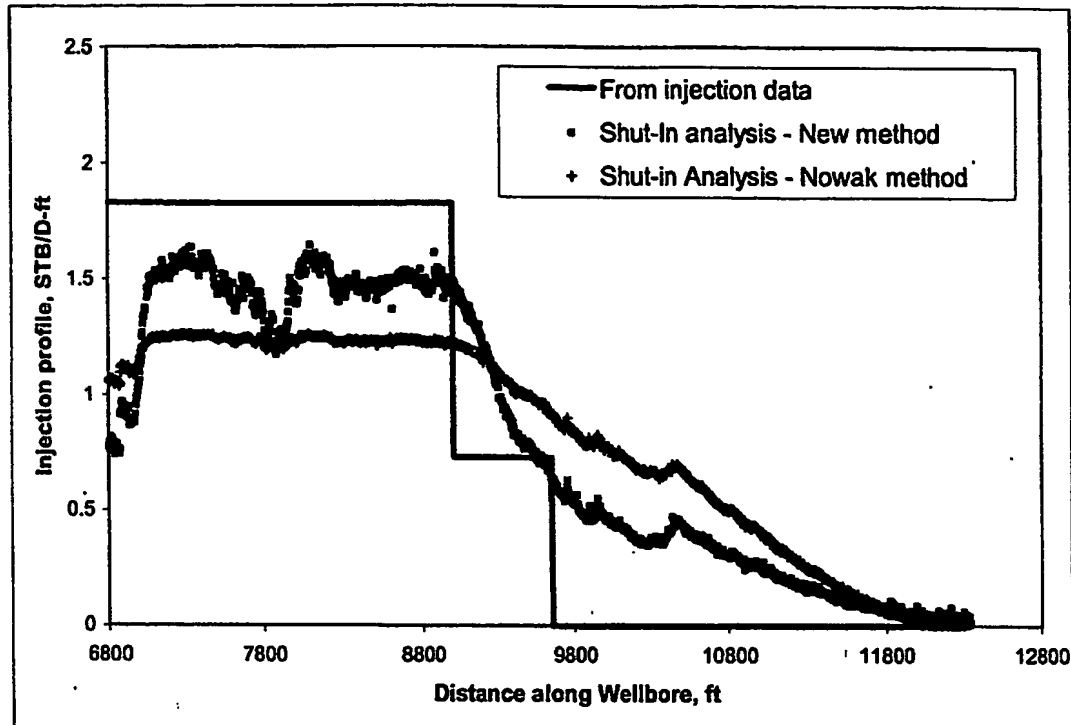


Fig. 36 – Comparison of the injection profile for different method.

Since we do not have the injection log to justify the accuracy of the analytical method, we used numerical simulation to assess the applicability of interpretation methods. We used the simulation model described in the previous section to simulate the temperature profile of the well. The temperature profile is matched with the measured temperature profile by manually adjusting the thermal conductivity of the reservoir and the permeability along wellbore. In assessing the applicability of the analytical method of flow profiling, we assumed that the best method would have the injection profile similar to the simulated injection profile.

Simulation Study of Safah-200

The data for the simulation is in Table 4. The reservoir dimension in the direction along wellbore is of 218 blocks. The well is completed in cell 3 to 216 in X direction, each cell has the length of 26 ft. Two first blocks and two last blocks in X direction have the size of 50 ft and 100 ft each to represent the effect at the tip of the well. The well is subject to

an injection rate of 4500 STB/D for 14 days, and then is shut-in for 1 day. The temperature at the heel of the well during early time of injection is the function of time and is taken from the similar well Safah-179 and is shown in Fig. 10. The initial value of the thermal conductivity of the reservoir is assumed to be 60 Btu/ft-D-F. The analytical estimate of the injection profile from alternative method is used to determine the distribution of the reservoir permeability along the wellbore. We assumed the linear relationship between flow rate and permeability: $k_r \sim q_i$. The permeability estimated from flow rate for each interval is applied in all grid block in Y and Z directions for that interval. With these input parameters, the simulated temperature profile at the $t=14$ days of injection and $t=1$ day of shut-in is shown on Fig. 37, together with measured temperature profile. We can see that the temperature profile from simulation is in good agreement with the measured temperature in the second half of the wellbore but too high for the first half of the well length. Reducing the injection rate in the first half of the well would result into smaller temperature recovery for this half of the well, but lower temperature in second half of the well during injection. Thus, the good match between simulated temperature and measured temperature can only be achieved both by reducing the thermal conductivity of the reservoir and by adjusting the permeability profile.

After several adjustments, the model gives good match with the measured data (Fig. 38). The final model has the reservoir thermal conductivity of 30 Btu/ft-D-F.

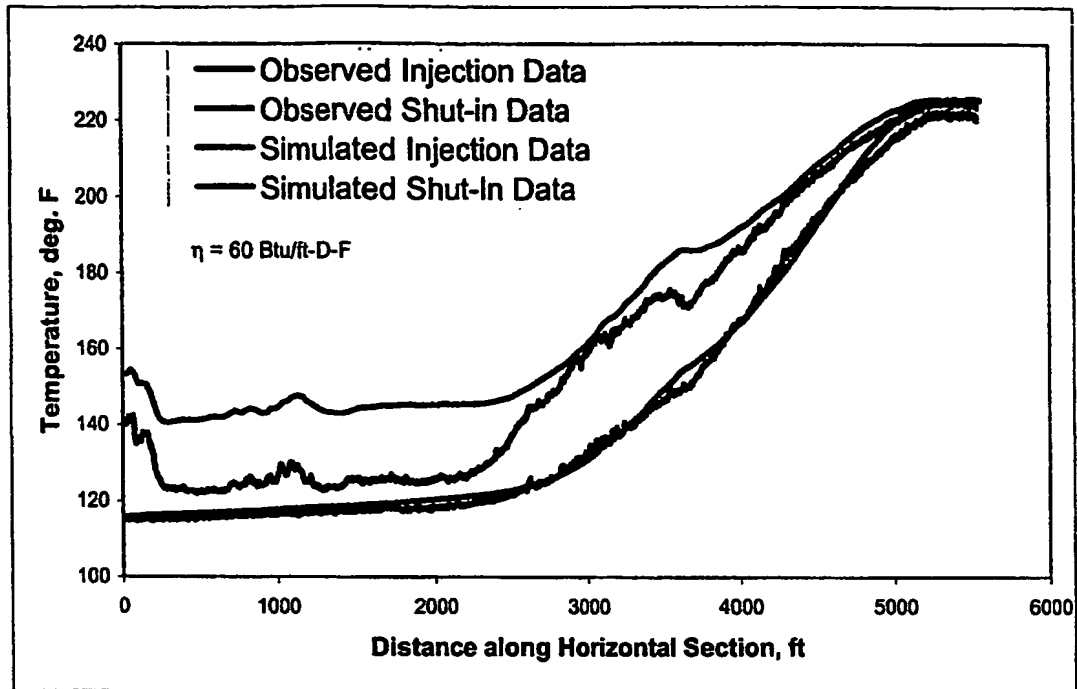


Fig. 37 – Simulated temperature – first run with the injection profile estimated from new method and reservoir thermal conductivity of 60 Btu/D-ft-deg.F.

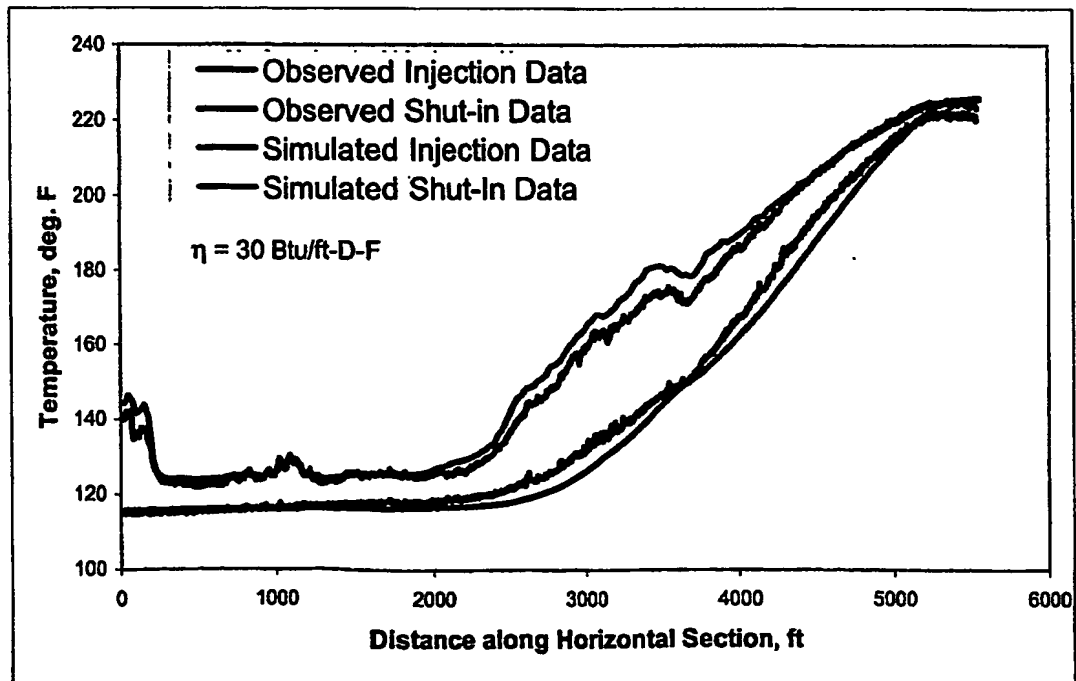


Fig. 38 – Simulated temperature – final run with the adjusted permeability along wellbore and reservoir thermal conductivity of 30 Btu/D-ft-deg.F.

The flow profile from the final simulation model is plot in Figs. 39-40 for comparison with the flow profiles, analytically estimated from temperature data. Injection profile estimated with the alternative method for shut-in temperature data is in very good agreement with the profile from simulation. The Nowak method underestimated the injection flow rate in the first half of the well. It is interesting to note that both methods for shut-in data overestimate the low flow rate and underestimated the high flow rate.

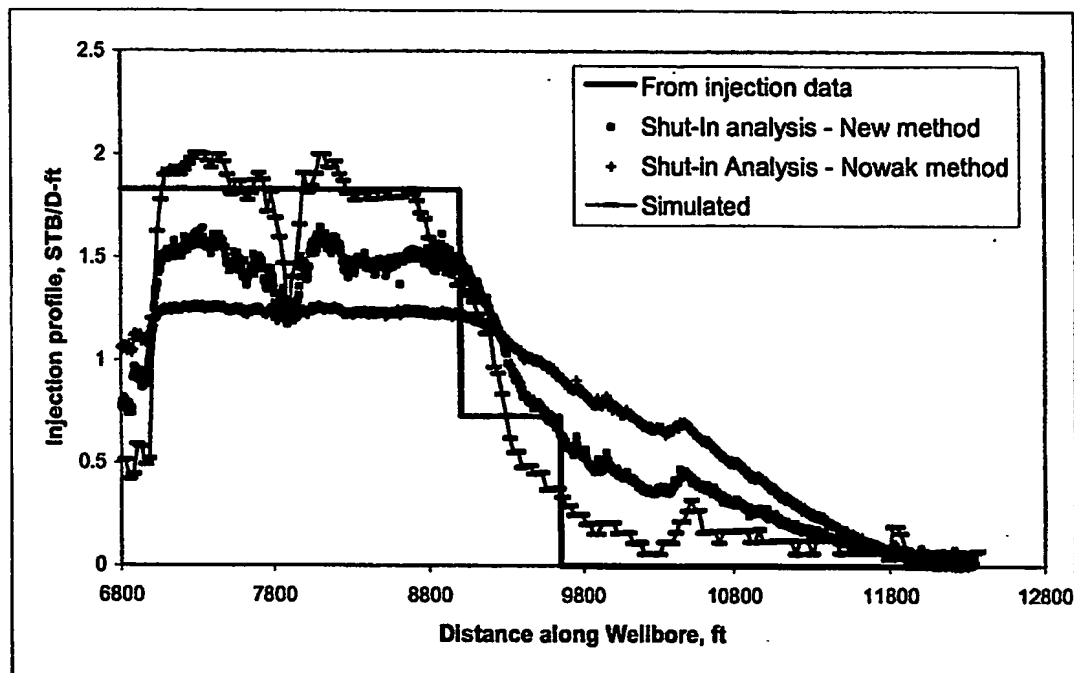


Fig. 39 – Injection profiles from different methods.

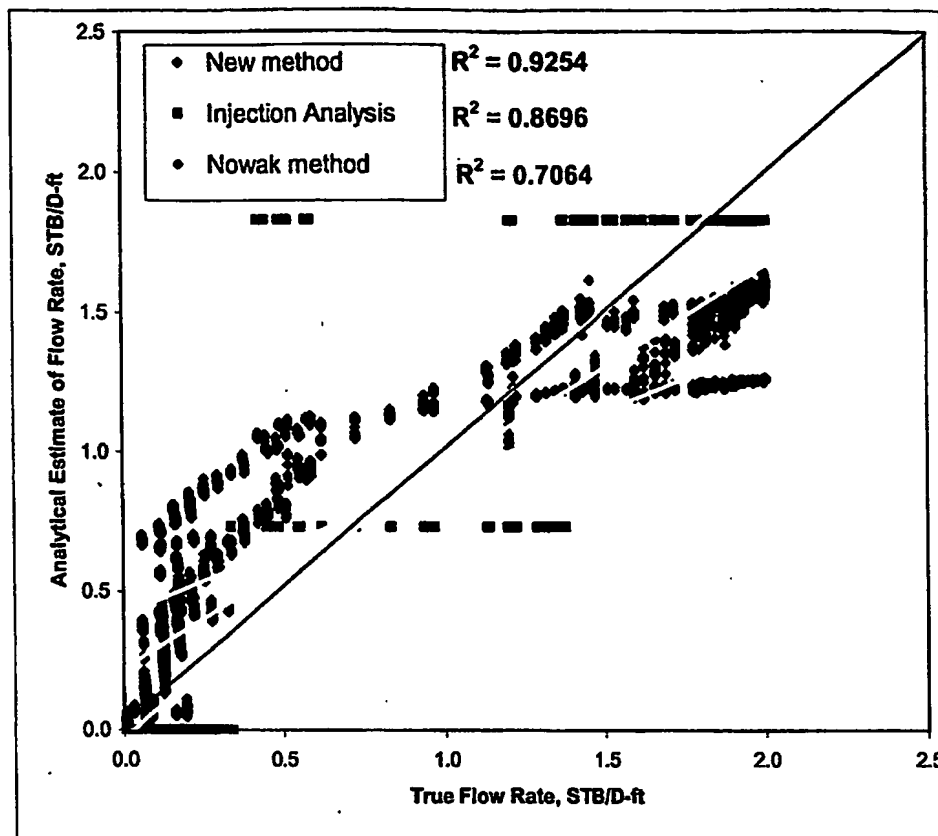


Fig. 40 – Comparison of the injection profile between analytical analysis and simulated result.

Effect of Injection History on Shut-in Analysis

While the analysis method for injection temperature data does not involve the complex heat transfer phenomenon and can be applied at any time during the life of the well, the shut-in temperature data depends on the injection time and the initial reservoir temperature. For the well with long injection time or unknown injection history, the applicability of this analysis method is not certain. We tried to take a further step toward the study of how this method behaves with time. For this purpose, the simulation model obtained by matching the temperature with observed temperature is run for 275 days. To simulate the possible effect of the heat transfer from top and base formations, 4 additional layers with zero permeability are introduced to the model. Two layers on the top have the

thickness of 50 ft and 100 ft. Two layers at the bottom have thickness of 50 ft and 100 ft. The heat capacity of those four layers is set at 350 Btu/ft³-F.

During 9 months of injection, five shut-in periods are taken place at 1 day, 5 days, 15 days, 100 days, and 270 days (Fig. 41).

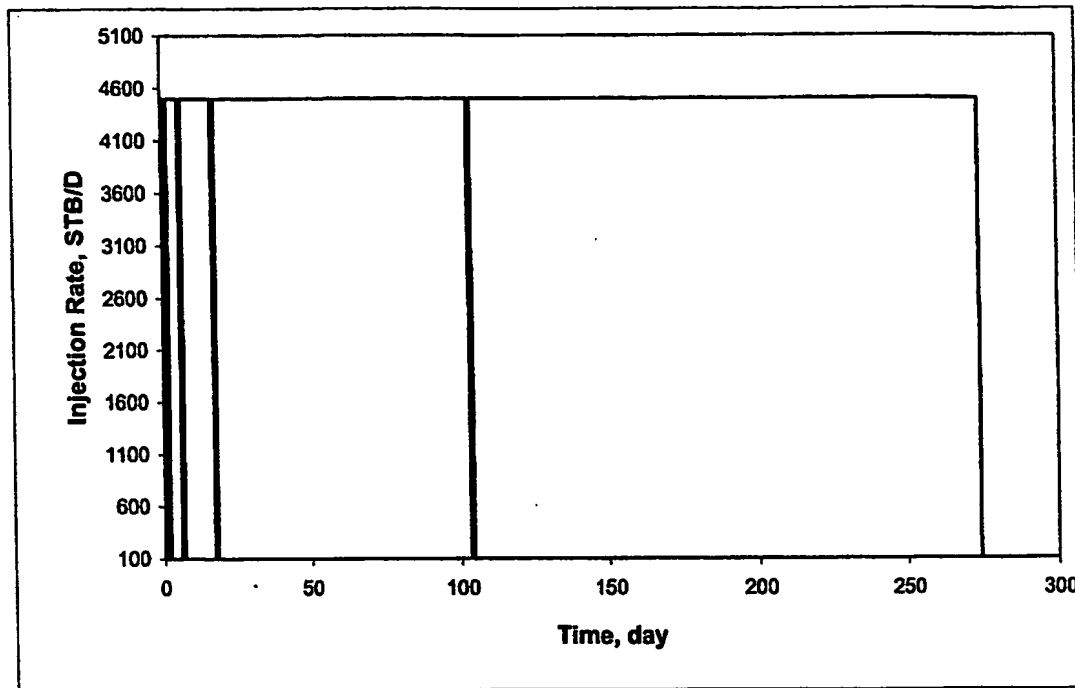


Fig. 41 – Well rate history for investigation the temperature behavior with time.

The plot of the temperature profile at the time before each shut-in period is shown in Fig. 42. The temperature profile during injection shows that the temperature front continues advancing toward the toe of the well (which is consistent with the actual data from other wells). However, the injection profile along the wellbore shows very little change with time (Fig. 43). It suggests that the change of the temperature profile during the injection after stabilization does not indicate the change in flow profile, but can be the effect of heat conduction process. This observation, however, does not exclude the possibility of the change of the injection profile in the real field condition, when the operation of other wells changes the pressure distribution in the reservoir. It only suggests that the change of the temperature during injection at the late time can be contributed mainly by heat conduction.

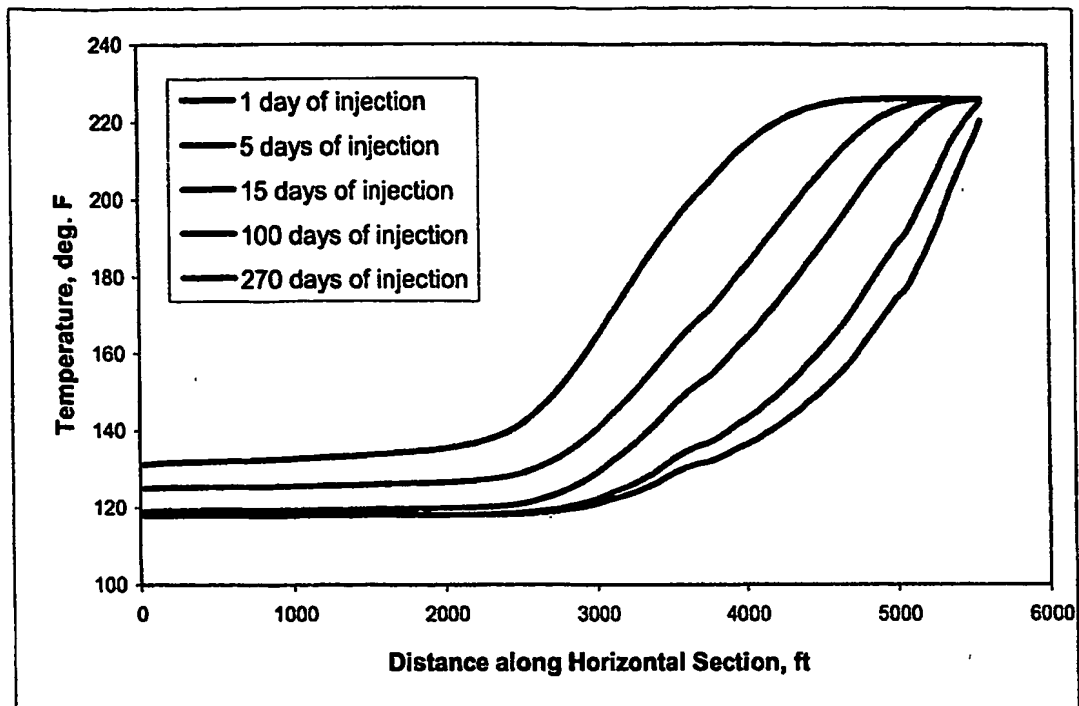


Fig. 42 – Temperature profile at different time of injection.

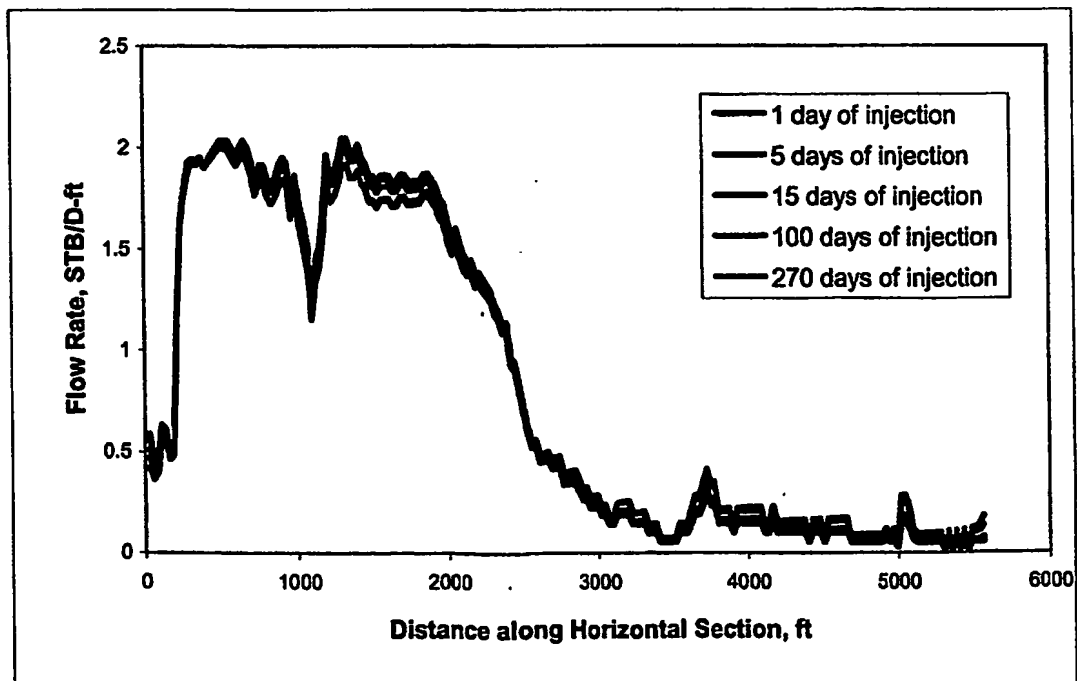


Fig. 43 – Simulated injection profile at different injection times.

The temperature profile at the end of each shut-in period is used for estimation of injection profile with the new analysis method. The result of analysis for each shut-in is shown in Fig. 44. The comparison with the actual flow profile is shown in Fig. 45. The estimated flow profile from shut-in data at different shut-in period shows that the accuracy of the analytical technique for injection profile deteriorates with time. This can be explained that with the long injection time, two major assumptions of the analytical method are being violated. Those assumptions are: 1) no heat transfer in X direction, and 2) sharp boundary of two temperature regions in the reservoir at the shut-in time. Thus, for better estimation of the injection profile at the later time of injection, the method that incorporates the history of the well and the heat transfer in X direction is needed.

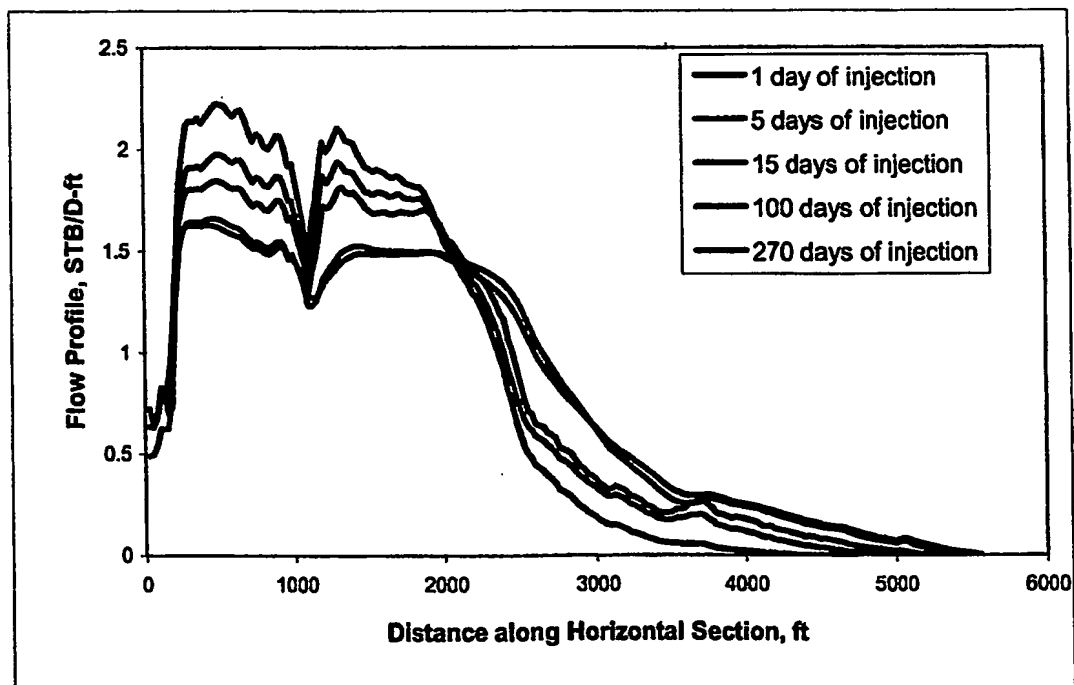


Fig. 44 – Analytically estimated injection profile from simulated temperature for different shut-in periods (shown in Fig. 41)

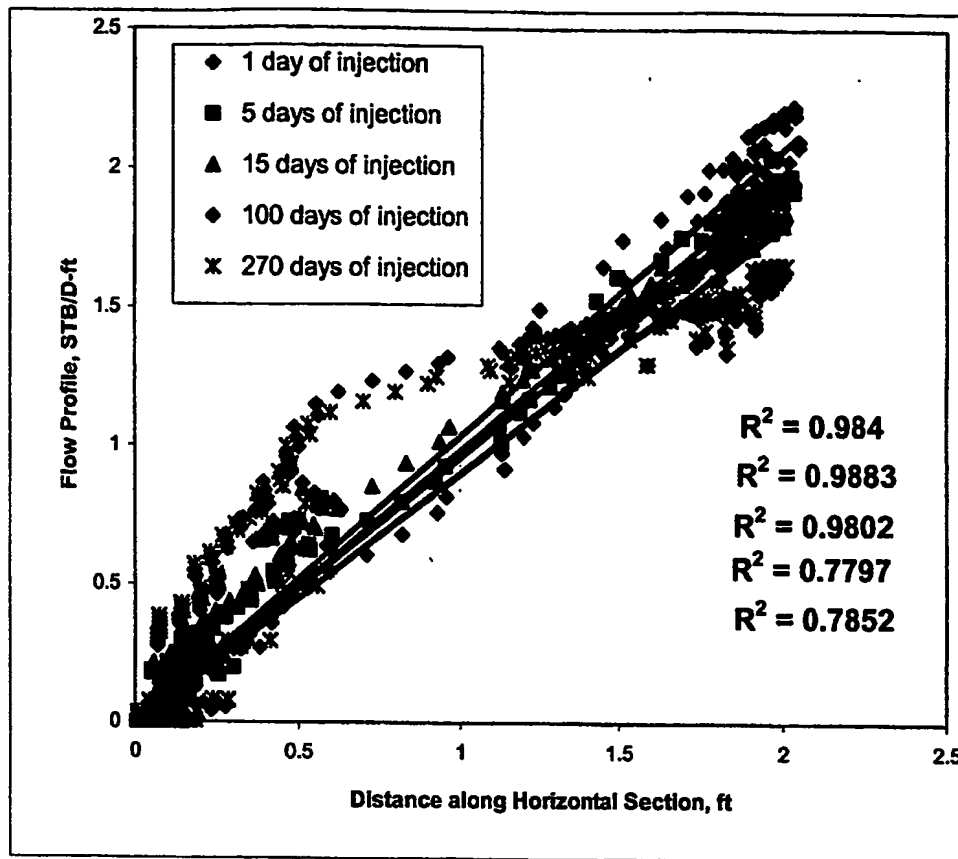


Fig. 45 – Comparison between estimated and true injection flow rate at time.

Conclusion

The early injection data following short shut-in period can be used to estimate the flow profile. This method of flow profiling analysis can be used at any time in the well life and only required enough temperature contrast of the fluid in the wellbore before injecting. This temperature contrast can be achieved by shutting the well for 1-2 days and letting the part of the well located above the injection formation to warm up. However, in the case of gradually increase of the permeability starting from the heel of the well, the sharp temperature contrast may not be observed.

The accuracy of the analysis method for shut-in temperature data is decreasing with injection time. For the well in this study, the correlation coefficient between estimated and true injection profile is slightly decreases with the time. Compare to the analysis of

injection data, shut-in data give more detailed flow profile estimation. Table 4 presents the comparison between the injection and shut-in analysis of the temperature data.

Finally, the simulation is a good tool for investigating the temperature behavior of the horizontal injection well. It also can be used to incorporate other reservoir parameters into analysis and for predicting temperature behavior at the later time of injection.

TABLE 4 – Comparison between injection and shut-in temperature analysis

Injection	Shut-in
General. Does not depend on injection history.	Depends on injection history.
Give gross feature of the injection profile	Give detailed feature of the injection profile
Does not depend on the reservoir properties	Depend on the near wellbore heterogeneity
Need high frequency injection data- synchronize with total injection rate	No need for high frequency data.
Difficult to be done automatically	Can be done automatically

For the better estimation of the injection profile in horizontal water injector, more work should be done to improve the accuracy and reliability of the analytical method, specifically in the following areas:

- determination of the injection front in wellbore from temperature data during the early injection.

incorporation of the well history into analysis of shut-in temperature data.

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Appendixes

Shut-in Analysis

The transient temperature response of a cool region with the radius of R_c in a hot formation can be expressed as:

$$T_D = \frac{1}{2\alpha} e^{-\frac{r^2}{4\alpha}} \int_0^{\frac{R_c}{2\alpha}} \zeta e^{-\frac{\zeta^2}{4\alpha}} I_0\left(\frac{r\zeta}{2\alpha}\right) d\zeta, \dots\dots\dots \text{A-1}$$

The solution for $r=r_w$ has the form as shown in Fig. 24 and can be approximate as:

$$\ln(T_D) = -1.950071 E^{-6} * x^6 + 8.955864 E^{-5} * x^5 - 1.550909 E^{-3} * x^4 + 0.0131941 * x^3 - 0.05875433 * x^2 - 0.8758939 * x - 1.571235$$

$$\text{where } x = \ln(\alpha/R_c^2), \dots\dots\dots \text{A-2}$$

Assuming that if the T_D for some injection interval is known, the value of α/R_c^2 can be

$$\text{found: } T_D = f\left(\ln \frac{\alpha}{R_c^2}\right), \text{ therefore: } \ln \frac{\alpha}{R_c^2} = f^{-1}(T_D), \text{ or: } R_c^2 = \alpha e^{-f^{-1}(T_D)}$$

Then we can expressed the injection rate at this interval as a function of T_D as follows:

$$R_c^2 = \frac{\Delta Q_i}{\pi L_i \phi (1 - S_{wi})} = \frac{q_i L_i t_{inj}}{\pi L_i \phi (1 - S_{wi})} = \frac{q_i t_{inj}}{\pi \phi (1 - S_{wi})} = \alpha e^{-f^{-1}(T_D)}$$

Or:

$$q_i = \frac{q_i t_{inj}}{\pi \phi (1 - S_{wi})} = \frac{\alpha \pi \phi (1 - S_{wi}) t}{t_{inj}} e^{-f^{-1}(T_D)} = A e^{-f^{-1}(T_D)}, \dots\dots\dots \text{A-3}$$

where $f^{-1}(T_D)$ is the solution for $\ln \frac{\alpha}{R_c^2}$ at T_D as shown in Fig. 24; A can be estimated as

$$A = \frac{\alpha \pi \phi (1 - S_{wi}) t}{t_{inj}}, \dots\dots\dots \text{A-4}$$

Since the temperature distribution in the actual reservoir is not the same as assumed, A can be used as a regression coefficient for all intervals with the constraint of total injection rate:

$$Q = A \sum_1^N e^{-f^{-1}(T_{Di})} L_i, \dots\dots\dots \text{A-5}$$

The interpretation procedure with the account of the magnitude of temperature recovery is following:

- 1- Assume reservoir temperature T_r and calculate the maximum of $(T_r - T_{si})$
- 2- Calculate the dimensionless temperature $T_{Di} = \frac{T_r - T_{si}}{T_r - T_{inj_i}} \frac{T_r - T_{si}}{\text{Max}(T_r - T_{si})}$
- 3- Solving for $f^{-1}(T_{Di})$ according to Eq.A-2
- 4- Estimate A, Eq. A-4
- 5- Calculate q_i , Eq. A-3
- 6- Adjust A so that total injection rate is match, Eq. A-5

Injection Analysis

Consider the horizontal well with constant injection rate Q . The well has length of L . The fluid is incompressible. The wellbore diameter is a function of the distance along wellbore and is denoted as D_x . The intake rate along the wellbore is assumed to be constant with time and is denoted as $q(x)$. Suppose that at time t , the displacement front is at distance x from the heel of the well. At time $t + dt$, the position of the front will be $x + dx$. The movement of the displacement front is caused by the difference between total volume of injected fluid entering the well Qdt and the total volume of fluid going

into formation in interval from heel to that front: $dt \int_0^x q(\zeta) d\zeta$

Or:

$$dV = Qdt - dt \int_0^x q(\zeta) d\zeta, \dots\dots\dots (B-1)$$

On the other hand:

$$dV = \frac{\pi D_x^2}{4} dx, \dots\dots\dots (B-2)$$

Then:

$$\frac{\pi D_x^2}{4} dx = Qdt - dt \int_0^x q(\zeta) d\zeta, \dots\dots\dots (B-3)$$

Since the speed of the displacement front is $v_\zeta = \frac{d\zeta}{dt}$, we have:

$$v_x = \frac{4}{\pi D_x^2} \left(Q - \int_0^x q(\zeta) d\zeta \right), \dots\dots\dots (B-4)$$

Eq. B-4 suggests that if we can measure the speed of the displacement front (by measuring temperature along wellbore at every time during early injection), we can construct the intake profile along wellbore by discretizing the integral term in Eq. B-4.

$$\frac{\pi D_x^2}{4} (x_i - x_{i-1}) = (t_i - t_{i-1}) \left[Q - q_i (x_i - x_{i-1}) - \sum_1^{i-1} q_j (x_j - x_{j-1}) \right], \dots\dots\dots (B-5)$$

or:

$$q_i = \frac{1}{(x_i - x_{i-1})} \left[Q - \frac{\pi D_i^2}{4} v_i - \sum_1^{i-1} q_j (x_j - x_{j-1}) \right], \dots\dots\dots (B-6)$$

where subscript i denotes the wellbore interval, at which the intake rate being determined.

Temperatur Analysis for Horizontal Injection Wells

Introduction

Horizontal wells have many advantages over conventional vertical wells, and have been extremely popular in the oil industry. The rapid increase in the applications of horizontal well technology brought an impetuous development of the procedures to evaluate the performances of horizontal wells.

Many papers have focused on the pressure analysis of horizontal wells. However, there are some limitations to the pressure analysis. One limitation is that distributive pressure sensing is not practical now. Another limitation is that the conventional transient pressure analysis assumes the wellbore is infinite conductive, i.e., the flux along the wellbore is uniform. This assumption is not reasonable for long horizontal wells. Pressure drop due to friction and non-uniform distribution of formation properties, such as skin factor, permeability and porosity, can result in non-uniform flux distribution. So, flux distribution is a key factor for horizontal well performance evaluation.

The DTS, distributed temperature sensing, has been successfully used for different wells. The distributive temperature profiles along horizontal wellbores are easily measured. The temperature profiles contain useful information of flux distribution.

The main objective of this paper is to establish a practical model to predict the temperature distribution along the wellbore when the injection flux is specified, or to estimate the injection flux distribution with measured temperature profile.

Assumption

- (1) The pressure and temperature gradient in the direction parallel to the axis of the horizontal well (x) are much smaller than those in the directions (y and z) perpendicular to the axis. So, the mass and heat transference along x -direction can be neglected.
- (2) The viscosity and density of oil and water are constants. So, the pressure and water saturation distribution are independent of temperature.
- (3) Isotropic formation.
- (4) Incompressible of injected fluid.
- (5) Open hole completion.

Wellbore Model

- (1) Wellbore flow rate distribution equation

Let $Q_{wi}(x,t)$ denote the injected fluid volume flow rate along the well bore (m^3/h), and $q_{wi}(x,t)$ denote the fluid volume rate injected into the formation for unit length of

the wellbore (m^2 / h). The mass conservation of injected fluid in the wellbore gives (see Fig.1):

$$Q_{wi}(x,t) - Q_{wi}(x+dx,t) - q_{wi}(x,t)dx = 0$$

$$\frac{\partial Q_{wi}}{\partial x} = -q_{wi}(x,t) \quad (1)$$

Integrating equation (1) from the heel to toe yields:

$$Q_{inj}(t) = Q_{wi}(0,t) = \int_0^L q_{wi}(x,t)dx$$

$$Q_{wi}(x,t) = Q_{inj}(t) - \int_0^x q_{wi}(\xi,t)d\xi \quad (2)$$

where $Q_{inj}(t)$ is the total injection rate at the heel of horizontal well.

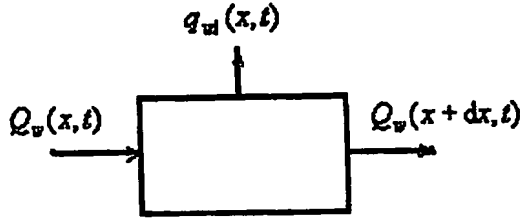


Fig. 1 Wellbore flow rate distribution

(2) Temperature distribution equation

The total heat stored in the tiny element dx is

$$Q_{well} = c_i A_w T_w(x,t)dx \quad (3)$$

Let $q_{Tw}(x,t) = 2\pi r_w \eta \left(\frac{\partial T}{\partial r} \right)_{r=r_w}$ denote the heat flow rate from formation into the unit

length wellbore, $T_w(x,t)$ denote the temperature profile along the wellbore. Energy conservation equation for element dx is:

$$\frac{\partial Q_{well}}{\partial t} = q_{win} - q_{wout} \quad (4)$$

where q_{win} and q_{wout} denote the heat rate flowing into and out of the tiny wellbore element dx . q_{win} is composed of two terms: the heat carried by the fluid flowing into the element through the wellbore cross-section area at x , $c_i Q_{wi}(x,t)T_w(x,t)$, and the heat flowing from formation to the wellbore element through the wellbore surface due to heat conduction, $q_{Tw}(x,t)dx$. q_{wout} is also composed of two terms: the heat carried by the fluid flowing out of the element through the wellbore cross-section area at $x+dx$, $c_i Q_{wi}(x+dx,t)T_w(x+dx,t)$, and the heat carried by the fluid flowing out of the element through the wellbore surface, $c_i q_{wi}(x,t)T_w(x,t)dx$.

$$q_{win} = c_i Q_{wi}(x,t)T_w(x,t) + q_{Tw}(x,t)dx$$

$$q_{rw}(x, t) = 2\pi\eta r_w \left(\frac{\partial T}{\partial r} \right)_{r=r_w}$$

$$q_{wout} = c_i Q_{wi}(x + dx, t) T_w(x + dx, t) + c_i q_{wi}(x, t) T_w(x, t) dx$$

Substituting q_{win} , q_{out} and equation (3) into (4) gives:

$$r_w - c_i \frac{\partial(Q_{wi} T_w)}{\partial x} + 2\pi\eta r_w \left(\frac{\partial T}{\partial r} \right)_{r=r_w} - c_i q_{wi} T_w = c_i A_w \frac{\partial T_w}{\partial t}$$

Substituting equation (1) into the above equation yields:

$$-c_i Q_{wi} \frac{\partial T_w}{\partial x} + 2\pi\eta r_w \left(\frac{\partial T}{\partial r} \right)_{r=r_w} = c_i A_w \frac{\partial T_w}{\partial t} \quad (5)$$

where c_i – heat capacity of injected fluid ($J/(m^3 \cdot ^\circ K)$);

A_w – flowing area in the wellbore (m^2).

η – thermal conductivity of the formation ($J/(m \cdot ^\circ K \cdot h)$).

Near Wellbore Heat Transportation – Water Injection

The near wellbore flow regime can be regarded as steady-state radial flow. Let us consider a tiny radial element between r and $r + dr$. The total heat stored in this element for water injection is composed of three terms: the heat stored in the water phase $Q_w = 2\pi r dr \phi s_w(x, r, t) c_w T(x, r, t)$, the heat stored in the oil phase $Q_o = 2\pi r dr \phi [1 - s_w(x, r, t)] c_o T(x, r, t)$, and the heat stored in the rock $Q_r = 2\pi r dr (1 - \phi) c_r T(x, r, t)$, i.e.,

$$\begin{aligned} Q_{res} &= Q_w + Q_o + Q_r \\ &= 2\pi r dr T(x, r, t) [s_w(x, r, t) \phi (c_w - c_o) + c_o \phi + (1 - \phi) c_r] \end{aligned} \quad (6)$$

where $T(x, r, t)$ is the temperature distribution in the reservoir, ϕ is porosity, c_o is the heat capacity of oil ($J/(m^3 \cdot ^\circ K)$), and $s_w(x, r, t)$ is water saturation.

Let $q_r(x, r, t) = 2\pi\eta r \frac{\partial T}{\partial r}$ denote the heat inward radial flow rate, $q_w(x, r, t)$ denote the water volume outward radial flow rate, and $q_o(x, r, t)$ denote the oil volume outward radial flow rate. The energy conservation equation for this radial element is:

$$\frac{\partial Q_{res}}{\partial t} = q_{rin} - q_{rou} \quad (7)$$

where q_{rin} and q_{rou} denote the heat rate flowing into and out of the tiny radial element dr . q_{rin} is composed of two terms: the heat carried by the oil and water flowing into the element through the inner surface at r , $[c_w q_w(x, r, t) + c_o q_o(x, r, t)] T(x, r, t)$, and the heat flowing into the tiny element through the outer surface at $r + dr$ due to heat conduction, $q_r(x, r + dr, t)$. q_{rou} is also composed of two terms: the heat carried by the oil and water flowing out of the radial element through the outer surface at $r + dr$, $[c_w q_w(x, r + dr, t) + c_o q_o(x, r + dr, t)] T(x, r + dr, t)$, and the heat flowing out of the tiny element through the inner surface at r due to heat conduction, $q_r(x, r, t)$.

$$\begin{aligned}
q_{rin} &= [c_w q_w(x, r, t) + c_o q_o(x, r, t)]T(x, r, t) + q_r(x, r + dr, t) \\
q_{rout} &= [c_w q_w(x, r + dr, t) + c_o q_o(x, r + dr, t)]T(x, r + dr, t) + q_r(r, t) \\
q_r(x, r, t) &= 2\pi\eta r \frac{\partial T}{\partial r}
\end{aligned}$$

Substituting the above equations and equation (6) into equation (7) yields:

$$\begin{aligned}
& [s_w(x, r, t)\phi(c_w - c_o) + c_o\phi + (1 - \phi)c_r] \frac{\partial T}{\partial t} + \phi(c_w - c_o)T(x, r, t) \frac{\partial s_w}{\partial t} \\
&= \frac{1}{2\pi r} \left[2\pi\eta \frac{\partial}{\partial r} \left(r \frac{\partial T}{\partial r} \right) - c_w \frac{\partial(q_w T)}{\partial r} - c_o \frac{\partial(q_o T)}{\partial r} \right]
\end{aligned} \quad (8)$$

Let $r_w(x, t)$ denote the water front at time t , and choose $r \leq r_w(x, t)$. Then we have:

$$s_w(x, r, t) = 1 - s_{or}, \quad q_w(x, r, t) = q_{wi}(x, t), \quad q_o(x, r, t) = 0$$

Near the wellbore, the heat flux can be also considered as a constant, i.e.,

$$2\pi\eta \frac{\partial}{\partial r} \left(r \frac{\partial T}{\partial r} \right) = \frac{\partial q_r}{\partial r} = 0$$

And equation (8) becomes:

$$[(1 - s_{or})\phi(c_w - c_o) + c_o\phi + (1 - \phi)c_r] \frac{\partial T}{\partial t} = -\frac{c_w q_{wi}(x, t)}{2\pi r} \frac{\partial T}{\partial r} \quad (9)$$

At the wellbore ($r = r_w$), we have:

$$[(1 - s_{or})\phi(c_w - c_o) + c_o\phi + (1 - \phi)c_r] \frac{\partial T_w}{\partial t} = -\frac{c_w q_{wi}(x, t)}{2\pi r_w} \left(\frac{\partial T}{\partial r} \right)_{r=r_w} \quad (10)$$

Combining equation (10) with equation (5) and choosing $c_i = c_w$ yield:

$$\left\{ \frac{(2\pi r_w)^2 \eta}{c_w q_{wi}(x, t)} [(1 - s_{or})\phi(c_w - c_o) + c_o\phi + (1 - \phi)c_r] + c_w A_w \right\} \frac{\partial T_w}{\partial t} = -c_w Q_{wi} \frac{\partial T_w}{\partial x} \quad (11)$$

Let:

$$a_{1w} = (1 - s_{or})\phi \left(1 - \frac{c_o}{c_w} \right) + \phi \frac{c_o}{c_w} + (1 - \phi) \frac{c_r}{c_w}, \quad a_2 = \frac{\pi r_w^2}{A_w}$$

$$a_w(x, t) = \frac{Q_{wi}(x, t)}{LA_w \left(1 + a_{1w} a_2 \frac{4\pi\eta}{c_w q_{wi}(x, t)} \right)}$$

Equation (11) becomes:

$$\frac{\partial T_w}{\partial t} + La_w(x, t) \frac{\partial T_w}{\partial x} = 0 \quad (12)$$

Near Wellbore Heat Transportation – Oil Injection

For oil injection, the water phase flow rate $q_w(x, r, t) = 0$ and water saturation $s_w(x, r, t) = s_{wi}$. The total heat stored in the radial element is composed of three terms: the

heat stored in the water phase $Q_w = 2\pi r dr \phi s_{wi} c_w T(x, r, t)$, the heat stored in the oil phase $Q_o = 2\pi r dr \phi [1 - s_{wi}] c_o T(x, r, t)$, and the heat stored in the rock $Q_r = 2\pi r dr (1 - \phi) c_r T(x, r, t)$, i.e.,

$$\begin{aligned} Q_{res} &= Q_w + Q_o + Q_r \\ &= 2\pi r dr T(x, r, t) [s_{wi} \phi (c_w - c_o) + c_o \phi + (1 - \phi) c_r] \end{aligned}$$

Similarly, we have:

$$\begin{aligned} q_{rin} &= c_o q_o(x, r, t) T(x, r, t) + q_r(x, r + dr, t) \\ q_{rout} &= c_o q_o(x, r + dr, t) T(x, r + dr, t) + q_r(r, t) \end{aligned}$$

The energy conservation equation for this radial element is:

Substituting the above equations into equation (7) yields:

$$[s_{wi} \phi (c_w - c_o) + c_o \phi + (1 - \phi) c_r] \frac{\partial T}{\partial t} = \frac{1}{2\pi r} \left[2\pi \eta \frac{\partial}{\partial r} \left(r \frac{\partial T}{\partial r} \right) - c_o \frac{\partial (q_o T)}{\partial r} \right] \quad (13)$$

In the steady state flow regime near the well bore, we have:

$$q_o(x, r, t) = q_{wi}(x, t), \quad \frac{\partial}{\partial r} \left(r \frac{\partial T}{\partial r} \right) = 0$$

And equation (13) becomes:

$$[s_{wi} \phi (c_w - c_o) + c_o \phi + (1 - \phi) c_r] \frac{\partial T}{\partial t} = \frac{c_o q_{wi}(x, t)}{2\pi r} \frac{\partial T}{\partial r} \quad (14)$$

At the wellbore ($r = r_w$), we have:

$$[s_{wi} \phi (c_w - c_o) + c_o \phi + (1 - \phi) c_r] \frac{\partial T_w}{\partial t} = - \frac{c_o q_{wi}(x, t)}{2\pi r_w} \left(\frac{\partial T}{\partial r} \right)_{r=r_w} \quad (15)$$

Combining equation (15) with equation (5) and choosing $c_i = c_o$ yields:

$$\left\{ \frac{(2\pi r_w)^2 \eta}{c_o q_{wi}(x, t)} [s_{wi} \phi (c_w - c_o) + c_o \phi + (1 - \phi) c_r] + c_o A_w \right\} \frac{\partial T_w}{\partial t} = -c_o Q_{wi} \frac{\partial T_w}{\partial x} \quad (16)$$

Let:
$$a_{1o} = s_{wi} \phi \left(1 - \frac{c_o}{c_w} \right) + \phi \frac{c_o}{c_w} + (1 - \phi) \frac{c_r}{c_w}, \quad a_2 = \frac{\pi r_w^2}{A_w}$$

$$a_o(x, t) = \frac{Q_{wi}(x, t)}{LA_w \left(1 + a_{1o} a_2 \frac{4\pi \eta}{c_w q_{wi}(x, t)} \right)}$$

Equation (16) becomes:

$$\frac{\partial T_w}{\partial t} + La_o(x, t) \frac{\partial T_w}{\partial x} = 0 \quad (17)$$

Boundary Condition and Initial Condition

The boundary condition is specified with the injection temperature at the heel ($x = 0$):

$$T_w(0, t) = T_{w0}(t) \quad (18)$$

The temperature at the heel $T_{w0}(t)$ can be determined with the wellbore heat transmission model put forward by H. J. Ramey.

The initial condition is:

$$T_w(x,0) = T_R \quad (19)$$

where T_R is the reservoir temperature.

Wellbore Temperature Prediction – Forward Problem

When the reservoir properties (porosity ϕ and permeability k), fluid properties (density ρ_o and ρ_w , viscosity μ_o and μ_w , relative permeability k_{ro} and k_{rw}), wellbore geometry (wellbore diameter r_w , fluid flow area A_w , roughness ε and the length of perforated section L) are specified, then the injection rate distribution $q_{wi}(x,t)$ can be determined with analytical model (e.x., model established by TUPREP) or numerical model (e.x., ECLIPSE100). And thus, with the properly defined boundary condition (18) and initial equation (19), we can predict the wellbore temperature profile $T_w(x,t)$ by solving equation (12) for water injection or equation (17) for oil injection.

Let $\bar{q}_0 = \frac{Q_{inj}(t_0)}{L}$ denote the average injection flux at time $t = t_0$, and

$$a_{Do}(x,t) = \frac{a_o(x,t)}{\bar{a}_o}, \quad a_{Dw}(x,t) = \frac{a_w(x,t)}{\bar{a}_w}$$

$$\bar{a}_w = \frac{\bar{q}_0}{A_w \left(1 + a_{1w} a_2 \frac{4\pi\eta}{c_w \bar{q}_0} \right)}, \quad \bar{a}_o = \frac{\bar{q}_0}{A_w \left(1 + a_{1o} a_2 \frac{4\pi\eta}{c_w \bar{q}_0} \right)}$$

Equations (12) and (17) can be rewritten as:

$$\frac{\partial T_w}{\partial t} + a_{Dw}(x,t) L \bar{a}_w \frac{\partial T_w}{\partial x} = 0 \quad (20)$$

$$\frac{\partial T_w}{\partial t} + a_{Do}(x,t) L \bar{a}_o \frac{\partial T_w}{\partial x} = 0 \quad (21)$$

Note the unit of $q_{wi}(x,t)$ and \bar{q}_0 is $\frac{m^3}{hour}$, so the unit of \bar{a}_w and \bar{a}_o is $\frac{1}{hour}$.

Let $\zeta = \frac{x}{L}$, $t_D = \bar{a}_w t$ for water injection or $t_D = \bar{a}_o t$ for oil injection. They denote the dimensionless variables. The dimensionless forms of equations (20) and (21) are:

$$\frac{\partial T_w}{\partial t_D} + a_{Dw}(\zeta, t_D) \frac{\partial T_w}{\partial \zeta} = 0 \quad (22)$$

$$\frac{\partial T_w}{\partial t_D} + a_{Do}(\zeta, t_D) \frac{\partial T_w}{\partial \zeta} = 0 \quad (23)$$

Or, both equations can be rewritten as:

$$\frac{\partial T_w}{\partial t_D} + a_{Di}(\zeta, t_D) \frac{\partial T_w}{\partial \zeta} = 0; \quad (i = o, w) \quad (24)$$

Let $\zeta_c(t_D)$ denote the characteristic curve along which the temperature keeps unchanging, i.e.,

$$dT_w = \frac{\partial T_w}{\partial t_D} + \frac{\partial T_w}{\partial \zeta_c} \frac{d\zeta_c}{dt_D} = 0 \quad (25)$$

Comparing equation (24) with (25) yields:

$$\frac{d\zeta_c}{dt_D} = a_{Di}(\zeta_c, t_D) \quad (26)$$

Equation (26) is the characteristic equation with respect to the partial differential equation (24). Equation (26) defines a group of curves, characteristic curves. We can prove that all characteristic curves do not intersect with each other. If one characteristic curve crosses the positive ζ coordinate, then the temperature on this curve is specified by the initial condition, i.e., equals to the reservoir temperature T_R . Otherwise, the curve will cross the positive t_D coordinate, and the temperature on this curve is specified by the boundary condition $T_w(t_{Dp})$, where t_{Dp} is the intersection of the characteristic curve with the time coordinate.

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